To: McKittrick, Alexis[McKittrick.Alexis@epa.gov]

From: Ramon Alvarez
Sent: Fri 2/5/2016 6:57:50 PM

Subject: RE: meeting on Hi-Flo Sampler with Touche Howard

Thank you!

From: McKittrick, Alexis [mailto:McKittrick.Alexis@epa.gov]

Sent: Friday, February 05, 2016 12:56 PM

To: Ramon Alvarez; lisa.song@insideclimatenews.org; nancy@ncwarn.org; terri.shires@aecom.com

Subject: Fwd: meeting on Hi-Flo Sampler with Touche Howard

Sent from my iPhone

https://epawebconferencing.acms.com/r2fk2tdpn9x/

From: Weitz, Melissa

Sent: Wednesday, December 23, 2015 4:35 PM

To: Weitz, Melissa; DeFigueiredo, Mark; Waltzer, Suzanne; McKittrick, Alexis;

Macpherson, Alex; Moore, Bruce; Thoma, Eben; Thompson, Lisa; Hambrick, Amy; Banks,

Julius; Irving, Bill Cc: Howard, Jodi

Subject: meeting on Hi-Flo Sampler with Touche Howard

When: Friday, February 5, 2016 1:30 PM-2:30 PM. Where: DCRoomWJCS4228AOAP/DC-OAR-OAP



A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

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To: allen@che.utexas.edu[allen@che.utexas.edu]; McKittrick, Alexis[McKittrick.Alexis@epa.gov]; terri shires@aecom.com[terri shires@aecom.com]; matt.harrison@aecom.com[matt.harrison@aecom.com]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Gunning, Paul[Gunning.Paul@epa.gov]; McCabe, Janet[McCabe.Janet@epa.gov] RAlvarez@edf.org[RAlvarez@edf.org]; shamburg@edf.org[shamburg@edf.org]; Fernandez, Roger[Fernandez.Roger@epa.gov]; rharriss@edf.org[rharriss@edf.org]; matt.harrison@urs.com[matt.harrison@urs.com]; ritterk@api.org[ritterk@api.org]; dnelson@edf.org[dnelson@edf.org]; sedlak-office@est.acs.org[sedlak-office@est.acs.org]; dmccabe@catf.us[dmccabe@catf.us]; dlyon@edf.org[dlyon@edf.org]; dave.maxwell@urs.com[dave.maxwell@urs.com]; dschroeder@catf.us[dschroeder@catf.us]; dzavala@edf.org[dzavala@edf.org]; Chuck Kolb[kolb@aerodyne.com]; Gamas, Julia[Gamas.Julia@epa.gov]; linda.lee@arb.ca.gov[linda.lee@arb.ca.gov]; bmordick@nrdc.org[bmordick@nrdc.org]; amrowka@arb.ca.gov[amrowka@arb.ca.gov]; adam.pacsi@chevon.com[adam.pacsi@chevon.com]; casey.pickering@erg.com[casey.pickering@erg.com]; Wisetiawa@arb.ca.gov[Wisetiawa@arb.ca.gov]; Smith, James-D[Smith.James-D@epa.gov]; Snyder, Jennifer[Snyder.Jennifer@epa.gov]; paige.sprague@tceq.texas.com[paige.sprague@tceq.texas.com]; michael.ege@tceq.texas.gov[michael.ege@tceq.texas.gov] From: Touche Howard Wed 12/9/2015 10:24:49 PM Sent: Subject: Draft Email to Dave Howard Energy Science and Engineering Analysis of UT Data Set 2015.pdf

Howard Energy Science and Engineering Analysis of UT Data Set 2015.pdf
ES&T Comment on Allen et al. Methane Emissions from Process Equipment.pdf
Dave Allen Response to ES&T Letter.pdf
Touche Response to Dave Allen Comment in ESE Submitted 09 10 2015.pdf

### Dave --

Now that the EPA is considering using your initial EDF study at production sites (published in PNAS in 2013) and your follow-up study on pneumatic controllers (published in ES&T in 2014), it's critical that we resolve the Hi-Flow sensor failure and other quality assurance issues surrounding those studies as soon as possible. The quickest way to do that is for us to directly discuss these issues with EPA, and I think once you understand the evidence, you'll be able to see the problems immediately. To that end, let's try to get together tomorrow or Friday. (Melissa and Alexis - I can come up and meet with you either day, and if Dave can't make it, he can call in.)

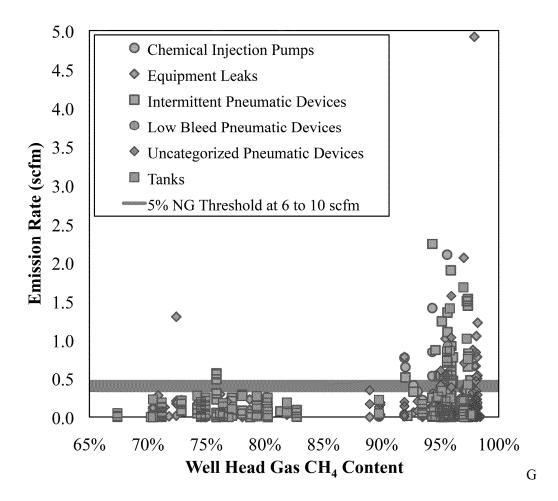
My biggest concern is safety -- having an instrument that reports natural gas leaks far lower than they actually are is clearly a huge safety issue, and as long as you tell people that this problem didn't occur in your work, it will be very hard for anyone to take it seriously. Meanwhile, for you and EPA, this also represents important health and environmental concerns. And of course since you were chair of the EPA Science Advisory Board while you were conducting this research, and the Hi-Flow sampler is one of the methods approved by EPA to make measurements for their greenhouse gas reporting program under Subpart W, I'm sure you feel a special responsibility to address these issues as soon as possible.

I've attached my ESE paper outlining the problems in your initial 2013 production study as well as my letter and your response about the 2014 study. I've also attached a reply that I wrote in response to your commentary on my paper in ESE, because even though you withdrew that commentary after seeing my response, I think my response did clarify some of the issues.

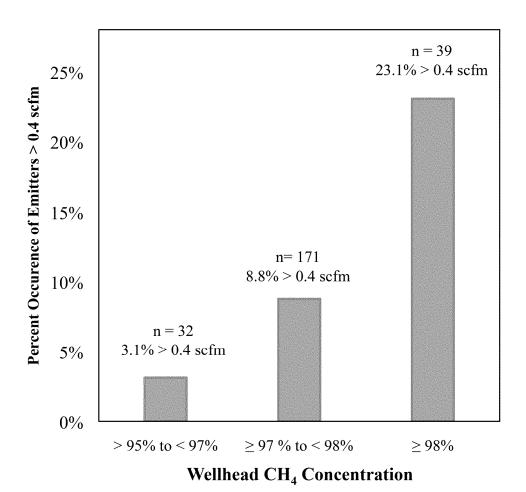
Since we unfortunately haven't had an opportunity to discuss these issues directly, I'll summarize the evidence here and what I believe are your counterpoints, based on your reviews of my paper and the commentary you submitted. I also want to allay your concerns, which you've stated to others, that I'm raising these issues because I want to sell my own samplers or services. I'm only wrapping up loose ends now, and after this I won't be working in this area any more.

The first issue is sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS), where it can fail to transition from the low range (0 to 5% gas) catalytic oxidation sensor to the high range (5 to 100% gas) thermal conductivity detector, which can cause the sampler to report large leaks as being much smaller that they are. We don't know why this happens, but there's no question that it can, because we demonstrated it in three different instruments, including yours. It doesn't seem to occur for pure methane streams, but we've seen it in the field for gas streams with methane content as high as 91% (J. Air Waste Manag. Assoc. 65:856–862. doi: 10.1080/10962247.2015.1025925).

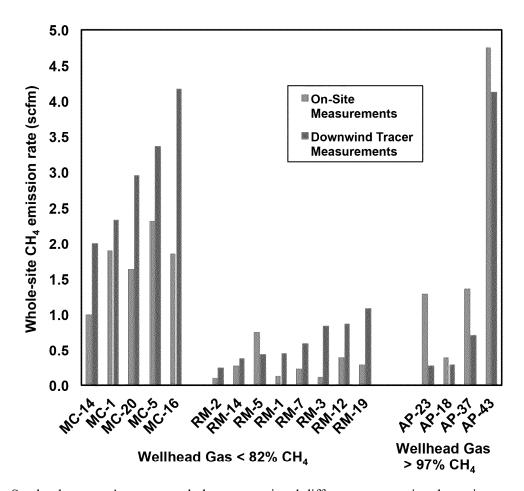
The effect of this problem is clear in your Phase I data, which I've plotted below showing emission rate as a function of site methane composition. As you can see, most of the high emitters only show up at sites with high methane compositions, and there's no reason that should happen in the real world, especially when you consider that it occurs for several different types of sources.



Now I believe your counter argument is that this phenomenon is due to air pollution control regulations reducing emissions in the Rocky Mountain region, where the methane content of the gas is lower as well. However, several things tell us that's not the cause of the trend in the figure above. First, even when you take the Rocky Mountain region out of the analysis, there's still far more high emitters at sites with higher methane content. Second, even within just the Appalachia region, the occurrence of high emitters increases dramatically over a very narrow range of site methane compositions, from 95% to 98% methane (shown below). What that tells us is that sampler can start seeing some of the high emitters once methane composition is in the range of 95%, but is still missing a lot of them until methane composition gets up to the 97 to 98% range. This is also an extremely important indicator that this problem could be occurring even for gas streams with methane content above 95%, meaning the problem could occur in all segments of the natural gas industry.



Finally, your emissions measurements made by tracer technique confirm that sensor failure occurred and that the trend of emission rate vs concentration is not caused by regional differences. Now, in your comment you said you found my analysis of your tracer data complex, probably because I showed how Hi-Flow measurements got lower and lower than the tracer measurements for sites with fewer estimated emissions from sources like tanks. So I've simplified that analysis, and just removed the two sites that had 98% or more of the emissions estimated as opposed to measured. This comparison of the tracer versus on site Hi-Flow measurements is shown below.



So clearly, as you've suggested, there are regional differences, assuming these sites are representative. The tracer data shows that the emissions from sites in the Rocky Mountain (RM) region are lower than the sites in the Mid-continent (MC) region, although in the same range as 75% of the Appalachia (AP) sites. But just as clearly, the sites with lower methane content (Rocky Mountain and Mid-continent, where sensor failure might occur consistently) have far lower (about a factor of two) Hi-Flow measurements than the tracer technique. Meanwhile, the sites with high methane content (Appalachia, where the problem isn't expected to occur) have Hi-Flow measurements close to or exceeding the tracer measurements. Keep in mind that because some of the on-site data comes from estimates, this masks the magnitude of the error, but at least this is a simple comparison.

Now if the variations between the tracer and the Hi-Flow were due to random experimental errors, then we'd expect roughly 50% of the sites to have tracer greater than Hi-Flow, and 50% lower. It's actually a 70/30 split, but the remarkable thing is that we can predict which region will have tracer greater than Hi-Flow and which won't. This is pretty much the same thing as me being able to walk into a bar and betting the barmaid that if I stand on her side of the bar and flip a coin it will always come up heads, but if I stand on my side of the bar and flip a coin, it will always come up tails. And in between drinks, we run that experiment, and it turns out that I'm

right 16 out of 17 times.

Now that's a bar bet I'd like to be able to make routinely.

You also said in your unpublished comment to ESE that the testing I conducted on your instrument and others in March of 2013 showed a low occurrence of this problem. That's true of course, but I was surprised you said that, since you know that immediately after we did that testing that I met with some very experienced Hi-Flow technicians who specifically told me that they had fixed some of their samplers that had been reporting leaks too low by upgrading the sampler's software. Since all of the samplers we tested when we tested yours had new generation software, the only real surprise is that we saw any failure at all, and that failure was in your sampler. So even though new software improves the problem, it doesn't fix it completely. Additionally, there are lots of these samplers around the US and the world using older software, and lots of data that has been collected using samplers prior to software upgrades.

One other argument you made was that your Phase I pneumatic data, made by Hi-Flow, was higher than your Phase II pneumatic data, collected by meter, and if your Hi-Flow had been reporting too low, this should have been the other way around. The reason this isn't true is that your Phase I pneumatic data is clearly an emitter data set (95% of them are emitting) while your Phase II data set is a comprehensive data set (about 21% are actual emitters). So you accidentally excluded sampling zero emitters in Phase I, which biases that data high by a factor of four to five, and offsets any Hi-Flow sensor failure. Additionally, the Phase II data actually shows exactly what I predicted to you it would show -- that the high emitters are more predominant at sites with lower methane compositions when measured by the inline meter as opposed to your Phase I measurements, where the sensor failure caused the high emitters at those sites to be under reported.

In any case, I think this shows that it probably would have been better to involve me directly in discussions you had with the EDF committees and others about this problem after I brought it to you in October of 2013, because I could have explained immediately why the reasons you thought this problem didn't affect your Phase I data were incorrect. It has been puzzling to me that given the overwhelming evidence, that this problem wasn't obvious to you, but I'm wondering if that might be due to inexperience with field measurements. As an example, in both your Phase I and Phase II papers, you incorrectly describe the operation of the Hi-Flow sensors, and without understanding that the Hi-Flow has to to switch back and forth between sensors to make accurate measurements, it's probably impossible for you to understand the sensor transition problem.

I'm wondering if inexperience might have also led to the problems in your Phase II work as well. It's a harsh environment for meters to be transported between field sites on rough roads and have raw natural gas run through them, and I think most people with experience in field measurements would have built in a routine testing of those meters during the project, rather than just check them before and after the project as you did. When you're out in the field looking at pneumatics, you see lots of them with oil or other hydrocarbon accumulations, so it's easy to picture how the meter sensor could get fouled, as yours did. I would think at least a weekly multi-point meter calibration and a daily single point flow check would be required to ensure

accurate measurements. which is what was done during the EDF WSU distribution work. The Indaco Hi-Flows that were used in that project have a very similar flow measurement system to your Fox meter, which is a thermal element in a tube, and even though the distribution study was a much less harsh environment, where leaks of relatively clean distribution gas were measured and the flow system dilutes those leaks with air before the gas hits the sensors, full scale weekly calibrations and single point daily flow checks were conducted.

Now, as you remember, while that project was ongoing, I found that one of your two primary meters was measuring too low by a factor of three. Well, that's not a surprise, given the harsh environment. I haven't used the particular meter that you were using before, but I did look at the manual for it, and it clearly states that a dirty sensor will cause measurements to be too low.

But I think how you addressed that issue indicates further inexperience. Since you don't mention the meter test I made showing it was a factor of three too low in your paper, but only indicate that you found the problem post project, it appears that you just kept using the meter, without trying to figure out what was wrong with it, and without instituting any additional meter checks.

Instead, it wasn't until the end of the project that you did any further checks, and at that point the response of the meter had changed again, to being low by about 34%. In order to understand more about the problem, you tried to use your Hi-Flow data to validate the meter results. Now your laboratory comparisons of the two for the most part are excellent and agree within 10%. But surprisingly, your field comparisons of the Hi-Flow to the meters are far worse. For measurements where either one or the other was >0.5 scfh, only 4 out of 19 (21%) are within 25%, and even for measurements >6 scfh, only 3 out of 10 (30%) are within 25% of each other. You do allude to the possibility of leaks affecting the measurements but don't give any indication that you tried to quantify the leaks that you think affected the measurements.

For comparison, in the WSU distribution work, where direct and tracer measurements were compared, 10 out of 14 (71%) were within 50% of each other, over a range of about 0.6 to 56 scfh. Now I would have liked that to be better, but I think I understand some of the challenges, one being that some of those that are far off are at really low emission rates, so missing just one source could throw you off a lot. But keep in mind, that's measuring the whole M&R facility or an underground leak, and comparing it to a downwind tracer flux measurement, so you have lots of challenges including multiple measurements at the facility and tracer source configurations.

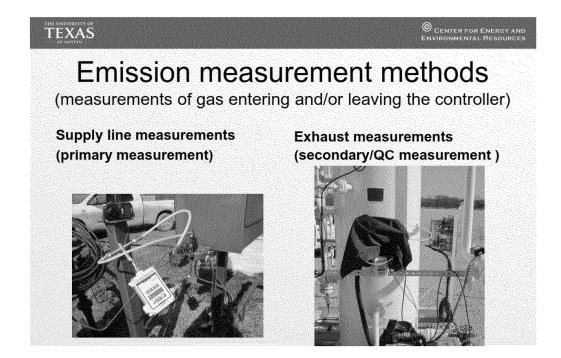
But for your pneumatic work, while doing a direct comparison of Hi-Flow to meters, for just single sources, only 7 of 19 (37%) were within 50% of each other over a similar emission range of 0.5 to 60 scfh.

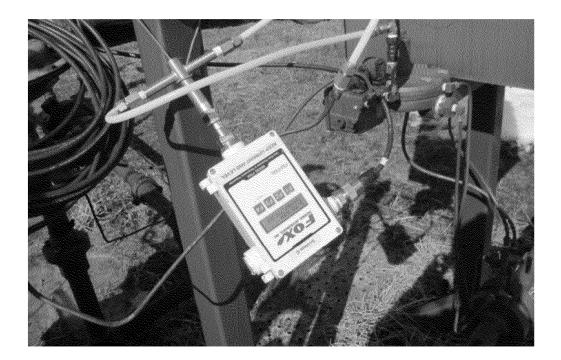
So unfortunately your comparison of High Flow to meters should not have been used to justify correcting your meter, especially when my direct test of that meter's performance mid-project showed it was much worse than the post project check indicated.

Another indication of the meter uncertainty came from Matt Harrison, who was present when I found that your meter was reading a factor of three too low, and said at the time, "Yeah, everyone knows that meter is flaky. You can hook it up to an pneumatic and hear the pneumatic

fire but not see anything on the meter."

Now, along with the sensor getting dirty, your meter measurements might have been affected by two other factors mentioned in the meter manual. These meters are supposed to be oriented upright, and you need a certain length of straight run (I think for the meter you were using, six inches) before the meter. However, it appears, looking at a slide from the presentation about the project on your website shown below, that those conditions weren't met either. Although you can see in the close up that the meter is marked with a label that says "Keep Upright and Level", that condition hasn't been met in either configuration pictured. Additionally, the entrance length doesn't appear to meet the required distance either.





I think these issues were all compounded by perhaps your lack of experience with what information editors and reviewers need to evaluate field measurement papers. Your meter problem is only mentioned in a footnote on page 59 of your Supplementary Information, and was likely missed by the editor and reviewers. But if reviewers with substantial field experience understood the entire picture -- that you only checked your calibration before and after the project, that there was an undisclosed mid project test showing meter performance was much worse than the correction you applied, that after you were shown one meter was faulty in the middle of the project that you simply continued to use it without finding out what was wrong or instituting improved calibration checks, "that everyone knew that meter was flaky," and that your Hi-Flow and meter field measurements don't compare very well -- I believe they would conclude that you didn't meet the fundamentals of quality assurance and that the paper would have been rejected.

So unfortunately neither the Phase I or Phase II data should be used by EPA. Although there may be large uncertainties in inventories, we shouldn't include numbers that have such large question marks. Think about cancer treatments. Those have very uncertain outcomes, but that doesn't mean that we don't want good quality assurance in cancer research or in the dosages of drugs or radiation therapy that are used. And when you consider the broad environmental impact of air toxics to the communities surrounding oil and gas facilities as well as the consequences of climate change, it's critical that we use the best data possible.

And as I said at the start, safety is my biggest concern regarding the HiFlow sensor failure, and I think perhaps again inexperience has caused you not to fully appreciate what a critical safety issue this is. I've spent a lot of time measuring leak rates at natural gas facilities, and I've seen

facility personnel shut down units in order to address large leaks that we found due to safety concerns -- I've done lots of leak measurement programs that were focused more on the integrity of the facility rather than the issue of greenhouse gases. Additionally, we don't know how the sampler might be used in the future -- for instance, given GTI's and WSU's work in distribution, it might be used to rank leaks for repair in that segment (even though the WSU study used a different version of the sampler not affected by this problem).

James Reason wrote a really great book about the Swiss cheese theory of disasters (*Reason*, *James (1997)*. *Managing the risks of organizational accidents*. Aldershot: Ashgate. ISBN 1840141042.) which is widely studied in aviation, engineering, and the fire service. In it he describes how the really terrible things that happen usually occur because there have been failures on several levels, and those failures line up to let something really bad happen.

We had a terrible example of that happen here in North Carolina a couple of years ago. A couple checked into a hotel, and the next morning they were dead. Seven weeks later, an 11 year old boy died in the same room, and although his mother survived, she had permanent brain damage.

All of that could have been avoided, because they were killed by carbon monoxide. You might have seen this on 20/20:

http://abcnews.go.com/US/north-carolina-best-western-room-225-open-deaths/story?id=21564280

Here's how it all lined up:

- 1) The hotel pulled an old pool heater out of another property and installed it at that hotel, even though it was at the end of its life, meaning it was inefficient and was at risk for producing more carbon monoxide, and they didn't get a city inspection permit;
- 2) The vent pipe was corroded, and let the CO escape under the room where everyone was killed;
- 3) There were holes in the fire place in the room that let more CO in that would have come in otherwise;
- 4) The CO detectors that were supposed to have been installed in the rooms were actually natural gas detectors, installed by mistake.

So that's what killed the first couple.

But here's why the little boy died:

1) Three days after the couple was killed, a family in the room above got really sick, and

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complained, but the hotel didn't pay attention;

- 2) The family of the first couple raised warnings with the hotel and police that it might be CO and again no one paid attention;
- 3) The medical examiner didn't visit the scene of the first couple and see that the wife had thrown up (an important clue in CO poisoning)
- 4) He also didn't put an expedite order on their blood work, so it sat for 40 days (two people simultaneously dead in an enclosed space -- a huge alarm bell for some toxic substance, especially CO);
- 5) He finally got the results four days before the child died in the room, but;
- 6) He sat on them for a week and by the time he finally sent them out to the local police; the child was had been killed and his mother permanently injured.

That's a tragic story, all right. And as you can imagine, the two families are suing everyone in sight that had anything to do with any of that, and I would too if I had lost a family member. Meanwhile, the DA also charged the head of the hotel management group with three counts of manslaughter, and all of those cases are still on going.

That's just one example of how tragic things can happen when we don't do everything possible to ensure people's safety. But if you do just a little bit of research, you'll see how frighteningly common that is.

So I know you'll want to address the Hi-Flow sensor failure issue immediately.

As I suggested at the start, let's do it this week. I can go up and meet with EPA tomorrow or Friday, and if you can't be there in person, you can call in, and you can have any interested parties from EDF or your production committees call in as well. i know everyone's busy, but this won't take more than an hour, and I think we should all be willing to make that much time for such a critical issue.

	Just let me	know when	the hest ti	me for all	of you is
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Thanks,

Touche'



Correspondence/Rebuttal

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### Response to Comment on "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers"

oward<sup>1</sup> has provided comments on our report of methane emissions from pneumatic controllers at natural gas production sites.<sup>2</sup> We disagree with the assertions made in the comment. The assertions include claims regarding sampling methods and comparisons with other measurement studies. We respond to each of these assertions below.

### SAMPLING METHODS

The primary assertions in the comment deal with our sampling method and claim (1) sensor failure in our Hi-Flow instrument, (2) faulty flow meters, and (3) resetting of malfunctioning pneumatic controllers when we inserted flow meters to conduct

(1) Sensor failure in the Hi-Flow instrument refers to a potential failure of the HiFlow sampler to change between its catalytic oxidation and thermal conductivity measurement modes at approximately 5% hydrocarbon concentration (~24 scf/h vent rate). To assess whether this potential crossover failure impacted measurements in Allen et al.,2 or our earlier work employing the instrument, we conducted laboratory testing, field testing, and additional analyses of field data.

Laboratory Testing: As documented in the Supporting Information for Allen et al.,2 prefield deployment laboratory testing of the sampler used in our work (referred to here as the University of Texas (UT) HiFlow sampler) demonstrated successful crossover between the two measurement modes for methane and a wet gas surrogate (70.5% methane

Field Testing: The study team participated in a twoday field test of several HiFlow samplers. Participants in the field testing included our team, the commenter, a consulting firm, an instrument provider and consulting firm, and a natural gas producer. During this field test, the UT HiFlow sampler successfully crossed-over on sites with methane concentrations in the produced gas ranging from 77%-91%. Over 2 days of testing, the UT HiFlow sampler crossed-over successfully in all but one test; that test occurred at a site with a produced gas containing 91% methane. Subsequent examination of the instrument indicated that it had lost calibration after losing power, then being restarted by personnel not on our study team. The sampling protocol in Allen et al.2 required a calibration check each time the HiFlow sampler was turned on. Once the calibration protocol was followed, the HiFlow sampler resumed proper

Additional Analysis of Allen et al.3 Data: Infrared (IR) video camera scans were taken on some sites during field work for Allen et al.,3 including for 118 of the 305 pneumatic controllers (39%) sampled in that work. These infrared camera scans were done immediately upon arrival at the site and thus were not exactly contemporaneous with the UT HiFlow measurements. Nevertheless, if the crossover problem were to have been prevalent, then the expectation would be to find infrared camera scans for which large leaks were detected by the IR camera but not measured by the UT HiFlow sampler. From this subset of data, 5 of the 118 devices had detectable emissions in the IR camera scan that were not captured by the subsequent UT HiFlow measurement. However, 7 of the 118 devices without detected emissions in the IR scan were found to have emissions between 0.2 and 5.0 scf/h by the UT HiFlow sampler. A likely explanation for these differences, based on the measurements we report in Allen et al.2 (see Figure 1 in that publication), is the intermittent venting pattern of some pneumatic controllers. Because of intermittent venting, some controllers would be expected to vent while being observed by the IR camera, but not when later being observed by the UT HiFlow sampler, and vice versa. Overall, the comparison with IR camera data suggests that the UT HiFlow sampler was capturing the emissions from pneumatic controllers in its measurements.

From these laboratory measurements, field measurements and additional analyses, we conclude that sensor failure did not significantly impact the measurements made with the UT HiFlow sampler in either Allen et al.  $^{2}$  or Allen et al.  $^{3}$ 

(2) The assertion of faulty flow meters refers to the readings of the flow meters being affected by deposits on the thermal conductivity sensor that could occur during the field campaign. These flow meters were inserted into the supply gas line of the pneumatic controllers during the field campaign and were the primary source of data in Allen et al.2 While not anticipated prior to the study, our observations in the field revealed that the supply gas to some controllers had the potential to create deposits, which can lead to controller malfunction as well as deposits on flow meters inserted into controller supply gas lines. Poststudy testing revealed that these deposits did occur on one of our flow meters (designated Fox A), but not the other two meters (Fox B and C). Because we were making measurements using both the UT HiFlow sampler and the flow meters for a subset of controllers in the field, we were able to identify the site at which a step change



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occurred in the flow measurement performance of the Fox A meter, due to deposits on the thermal conductivity sensor. We applied a correction factor, based on pre- and poststudy testing done in our laboratory, to the flow rate measurements made by the Fox A meter after the deposits occurred. This adjustment was documented in the data set we reported in the Supporting Information (Section S4, particularly Table S4-4) for Allen et al.<sup>2</sup> In the Supporting Information, we describe the adjustment and flag every controller measurement to which the adjustment was applied. Thus, we believe that we have corrected for the impact that deposits on one of the flow meters had on our measurements, in a transparent and well-documented

(3) Resetting of malfunctioning pneumatic controllers refers to potential alteration of pneumatic controller behavior due to the insertion of the supply gas meter. While this cannot be ruled out as a possibility, we have no evidence that this occurred. We believe that we minimized the potential for this behavior by having a site operator, familiar with the site and the controllers (rather than the study team), insert the flow meter, while the study team observed the process. If there were a high pneumatic controller bleed rate that became low or zero after the connection, this should have been observable by the company operator and the field team through the audible venting of the controller. After the flow meter was inserted, the study team waited approximately 5 min before collecting flow measurement data.

### COMPARISON WITH OTHER MEASUREMENT STUDIES

The comment makes comparisons between the data reported in our field work<sup>2</sup> and measurements reported in previous measurements by our team<sup>3</sup> and measurements made by a study conducted in British Columbia and Alberta.4 We caution against making direct comparisons without correcting for differences in sample sets and the way in which controllers are classified. We note that while our work<sup>2</sup> sampled all controllers at conventional and unconventional natural gas well sites in many production regions, the Canadian study was conducted in only one production region and selected controllers with manufacturer reported bleed rates in excess of 4.2 standard cubic feet per hour (scf/h). The Allen et al.3 study sampled only relatively young wells producing from shale formations. In addition, classifications of controllers (such as intermittent) can be done based measured emissions from the controllers (as in Allen et al.2) or based on the design of the controller (as in the Canadian study and our earlier work<sup>3</sup>), and there is a high degree of variability in these classifications. We have described these differences in our report,2 identifying and correcting for these sampling differences, and will not repeat those comparisons here. We emphasize, however, that such comparisons must be done with caution. The comparisons in the comments do not appear to have accounted for the differences in sample populations.

David T. Allen\*,† David W. Sullivan<sup>†</sup> Matt Harrison<sup>∓</sup>

<sup>†</sup>Center for Energy and Environmental Resources, University of Texas at Austin, 10100 Burnet Road, Building 133, M.S. R7100, Austin, Texas 78758, United States

<sup>‡</sup>AECOM (formerly URS Corporation), 9400 Amberglen Boulevard, Austin, Texas 78729, United States

### **AUTHOR INFORMATION**

Corresponding Author

\*E-mail: allen@che.utexas.edu.

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Correspondence/Rebuttal

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### Comment on "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers"

llen et al. (2014) recently published measurements of Inatural gas (NG) emissions from pneumatic controllers (PCs) at NG production sites in the United States in ES&T.1 Limitations to this work include (1) faulty flow meters; (2) sensor failure in their Hi-Flow instrument; and (3) potential reset of malfunctioning PCs when installing flow meters. These problems could cause the authors' emission estimates to be underestimated by a factor of 3.

Most measurements were made by installing flow meters in the supply gas lines of the devices, which required temporarily turning off the supply gas. On March 18, 2014, in collaboration with the authors, I tested these meters (designated Fox A and Fox C) while the project was underway. The Fox A meter read an average of 65% lower than the Fox C meter (which agreed with a rotameter to within 10%). The University of Texas (UT) team replaced the meter cable, but problems persisted and the Fox A meter was not tested further that day. The authors continued using the Fox A meter during their program but without incorporating the March 18 test results; the authors only noted that Fox A read 37% lower than Fox C during post project calibration due to "condensation of an oily substance on the sensor". However, even with this correction, measurements made with Fox A were a factor of 2 lower than Fox C on March 18. Volatiles likely accumulated and dissipated on both meters throughout the project; with calibrations only before and after the project, and the large difference in Fox A's measurements on March 18 compared to these corrections, the accuracy of these meters is highly questionable.

Although the authors cite the agreement of five Hi-Flow sampler and meter measurements for emission rates >6 scfh, at least four of those comparisons were for Fox A. Additionally, four of these comparisons were made at either the same or nearby sites. Consequently, these comparisons primarily show meter performance for a short time frame and for one meter. In contrast, all available comparisons of Hi-Flow and meter measurements show on average the meters read only 71% of the Hi-Flow measurements; removing one Hi-Flow measurement that the authors thought low due to incomplete capture indicates on average the meters read only 58% of the Hi-Flow measurements.

Also during the March 18 tests, the UT Bacharach Hi-Flow sampler failed to transition between low and high range sensors, underestimating emission rates by up to 2 orders of magnitude.<sup>2</sup> The instrument was recalibrated after this occurred, eliminating this failure for the rest of that day, but the performance of the instrument before and after our testing is unknown. This could cause underestimates in the Hi-Flow measurements made during this project<sup>1</sup> and previously.<sup>3</sup>

Finally, in my experience, manual actuation of malfunctioning PCs with high bleed rates may reset them to lower bleed rates; turning the supply gas off and on to install meters might have similarly reset devices. Figure 1 compares intermittent PC

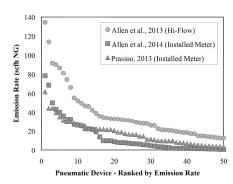


Figure 1. Intermittent pneumatic device emission rates measured by meters and Hi-Flow Sampler. The lower peak emitters observed in the studies made by installing meters is likely due to resetting malfunctioning controllers by turning the supply gas to devices off and back on during meter installation.

bleed rates from three studies: Allen et al. (2013);3 Prasino (2013),4 which also installed meters, and the study under discussion; and Allen et al. (2014).1 The two studies which installed meters have significantly lower peak emitters than the previous study done by Hi-Flow,3 which did not require stopping the supply gas. The current study 1 noted that intermittent PCs with bleed rates larger than 40.2 scfh were malfunctioning; only 1.3% of the intermittent PCs in (1) were above this bleed rate compared to 11% in the previous study.3 Consequently, the scarcity of high emitters in the current study<sup>1</sup> is likely due to reset devices, because other factors, that is, greater liquid production rates, would not be sufficient to cause the greater occurrence of high emitters observed in (3). The effect of these missing malfunctioning controllers can be estimated by adding the emission rates for intermittent PCs observed by (3) that are greater than the largest emission rate for intermittent PCs observed in (1). This would increase the average emission rate from intermittent PCs in the current study by 81%. If the number of missing high emitters is adjusted for the increased sample size of the current study compared to (3), then the average emission rate would increase by 298%.

### Touché Howard\*

Indaco Air Quality Services, Inc., Durham, North Carolina 27713, United States



Corresponding Author

\*Phone: 919-943-9406; e-mail: touche howard@earthlink.net.

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Correspondence/Rebuttal

### Notes

The author declares no competing financial interest



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# **Energy Science & Engineering**

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RESEARCH ARTICLE

# University of Texas study underestimates national methane emissions at natural gas production sites due to instrument sensor failure

Touché Howard

Indaco Air Quality Services, Inc., Durham, North Carolina

### Keywords

Greenhouse gases, methane, natural gas

### Correspondence

Touché Howard, Indaco Air Quality Services, Inc., Durham, NC. Tel: (919) 943-9406; E-mail: touche.howard@indacoaqs.com

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### Abstract

The University of Texas reported on a campaign to measure methane  $(CH_A)$ emissions from United States natural gas (NG) production sites as part of an improved national inventory. Unfortunately, their study appears to have systematically underestimated emissions. They used the Bacharach Hi-Flow® Sampler (BHFS) which in previous studies has been shown to exhibit sensor failures leading to underreporting of NG emissions. The data reported by the University of Texas study suggest their measurements exhibit this sensor failure, as shown by the paucity of high-emitting observations when the wellhead gas composition was less than 91% CH<sub>4</sub>, where sensor failures are most likely; during follow-up testing, the BHFS used in that study indeed exhibited sensor failure consistent with under-reporting of these high emitters. Tracer ratio measurements made by the University of Texas at a subset of sites with low CH4 content further indicate that the BHFS measurements at these sites were too low by factors of three to five. Over 98% of the CH 4 inventory calculated from their own data and 41% of their compiled national inventory may be affected by this measurement failure. Their data also indicate that this sensor failure could occur at NG compositions as high as 97% CH<sub>4</sub>, possibly affecting other BHFS measurement programs throughout the entire NG supply chain, including at transmission sites where the BHFS is used to report greenhouse gas emissions to the United States Environmental Protection Agency Greenhouse Gas Reporting Program (USEPA GHGRP, U.S. 40 CFR Part 98, Subpart W). The presence of such an obvious problem in this high profile, landmark study highlights the need for increased quality assurance in all greenhouse gas measurement programs.

### Introduction

The climatic benefits of switching from coal to natural gas (NG) depend on the magnitude of fugitive emissions of methane ( $\mathrm{CH_4}$ ) from NG production, processing, transmission, and distribution [12, 13, 27]. This is of particular concern as the United States increasingly exploits NG from shale formations: a sudden increase in  $\mathrm{CH_4}$  emissions due to increased NG production could trigger climate "tipping points" due to the high short-term global warming potential of  $\mathrm{CH_4}$  (86× carbon dioxide on a 20-year time scale) [19]. The United States Environmental

Protection Agency (USEPA) estimates  $\mathrm{CH_4}$  emissions from the NG supply chain by scaling up individual ground-level measurements, mostly collected by reporting from industry [26]. However, some recent studies have questioned whether these "bottom-up" inventories are too low, since airborne measurements indicate that  $\mathrm{CH_4}$  emissions from NG production regions are higher than the inventories indicate [5, 14, 17, 20, 21].

In order to help determine the climate consequences of expanded NG production and use, and to address the apparent discrepancy in top-down and bottom-up measurements, the University of Texas (UT) at Austin and the

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UT Study Underestimates Methane Emissions

Environmental Defense Fund launched a large campaign to measure CH4 emissions at NG production sites in the United States [1]. This study used both existing EPA GHG inventory data and new measurements to compile a new national inventory of CH<sub>4</sub> emissions from production sites. Forty-one percent of this new inventory was based on measurements made by [1], which included measurements of emissions from well completion flowbacks as well as measurements of emissions from chemical injection pumps, pneumatic devices, equipment leaks, and tanks at 150 NG production sites around the United States already in routine operation (measurements from tanks were not used for inventory purposes). However, the measurements of emissions at well production sites already in operation (which comprised 98% of the new inventory developed by [1]) were made using the Bacharach Hi-Flow Sampler (BHFS; Bacharach, Inc., New Kensington, PA) and recent work has shown that the BHFS can underreport individual emissions measurements by two orders of magnitude [10]. This anomaly occurs due to sensor transition failure that can prevent the sampler from properly measuring NG emission rates greater than ~0.4 standard cubic feet per minute (scfm; 1 scfm =  $1.70 \text{ m}^3 \text{ h}^{-1}$  or  $19.2 \text{ g min}^{-1}$  for pure CH<sub>4</sub> at 60°F [15.6°C] and 1 atm; these are the standard temperature and pressure used by the U.S. NG industry). Although this failure is not well understood, it does not seem to occur when measuring pure CH<sub>4</sub> streams, but has been observed in four different samplers when measuring NG streams with CH4 contents ranging from 66% to 95%. The sampler's firmwareversion and elapsed time since last calibration may also influence the occurrence of this problem [10, 18].

This paper presents an analysis of the UT [1] emissions measurements that were made with the BHFS, and shows that high emitters (>0.4 sofm [0.7  $\rm m^3~h^{-1}$ ]) were reported very rarely at sites with a low CH<sub>4</sub> content in the well-head gas (<91%), consistent with sensor transition failure. It also details testing of the exact BHFS instrument used in that study and shows the occurrence of this sensor failure at an NG production site with a wellhead composition of 91% CH<sub>4</sub> (the highest CH<sub>4</sub> concentration site available during testing). Finally, the downwind tracer ratio measurements made by [1] at a subset of their test sites are reexamined and indicate that the BHFS measurements made at sites with low wellhead CH<sub>4</sub> concentrations were too low by factors of three to five.

## **Evidence of BHFS Sensor Transition Failure in the UT Dataset**

The Allen et al. [1] UT dataset is unique due to the large number of BHFS measurements made across a wide geographic range, the variety of emissions sources

(equipment leaks, pneumatic devices, chemical injection pumps, and tanks) and the wide range of NG compositions (67.4–98.4%  ${\rm CH_4}$ ) that were sampled. As such, the UT study provides an important opportunity to evaluate the occurrence of sensor transition failure in the BHFS as well as the impact of this issue on emission rates and emissions factors based on measurements in other segments of the NG supply chain.

The BHFS uses a high flow rate of air and a loose enclosure to completely capture the NG-emitting from a source, with the emission rate calculated from the total flow rate of air and the resulting sample NG concentration, after the background NG concentration is subtracted. The sampler uses a catalytic oxidation sensor to measure sample concentrations from 0% to 5% NG in air, but must transition to a thermal conductivity sensor in order to accurately measure sample concentrations higher than 5%. It is the failure of the sampler to transition to the higher range that has been previously observed by Howard et al. [10] and which can prevent the sampler from correctly measuring emission rates larger than 0.3–0.5 scfm (0.5–0.9 m³ h<sup>-1</sup>) (corresponding to sampler flow rates of 6–10 scfm [10–17 m³ h<sup>-1</sup>]). Figure 1 summarizes data

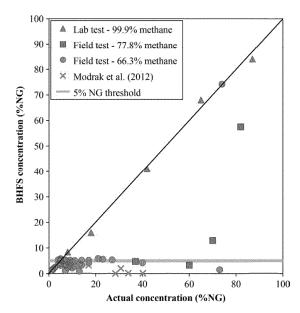


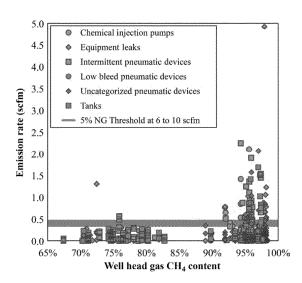
Figure 1. Occurrence of sensor transition failure in BHFS instruments with natural gas of varying CH<sub>4</sub> content from field and lab testing and from emission measurement studies (data from [10, 18]). NG concentrations in the BHFS sampling system measured by the BHFS internal sensor are compared to independent measurements of the sample NG concentrations. The 5% NG sample concentration threshold is the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity. BHFS, Bacharach Hi-Flow Sampler; NG, natural gas.

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showing the occurrence of sensor transition failure in several BHFS instruments during both fieldand laboratory testing as well as an example of the failure that occurred during an emission measurement study [10, 18].

Figure 2 presents the BHFS emission measurements from [1] as a function of percent  $\mathrm{CH_4}$  in wellhead gas at each site. Figure 2 also shows a line corresponding to emission rates of 0.3–0.5 scfm (0.5–0.9  $\mathrm{m^3\ h^{-1}}$ ), which represents the range of emission rates that would require transition from the catalytic oxidation sensor to the thermal conductivity sensor at sample flows ranging from 6 to 10 scfm (10–17  $\mathrm{m^3\ h^{-1}}$ ).

As seen in Figure 2, there are very few measurements in the thermal conductivity sensor range (above  $\sim 0.4$  scfm  $[0.7 \text{ m}^3 \text{ h}^{-1}]$ ) at sites where the wellhead gas composition of CH<sub>4</sub> is less than 91%, and this is true across all source categories. Raw data for sample flowand concentration from the BHFS were not provided in [1] supplemental information, so for this analysis, an average BHFS sample flowrate of 8 scfm (14 m  $^3$  h $^{-1}$ ) has been assumed, which is the lower of the two sampling flows specified by the Bacharach operating manual [4]. At this sample flowrate, an emission source of 0.4 scfm (0.7 m $^3$  h $^{-1}$ ) corresponds with a sample concentration of 5% NG in air, above



**Figure 2.** Emission rates of various sources measured by BHFS at NG production sites versus CH  $_4$  concentration of the wellhead gas (data from [1]). The solid line indicates the maximum emission rate that could be measured by the catalytic oxidation sensor only (i.e., in the case of sensor transition failure). For sites with a NG composition greater than 91% CH $_4$ , 13.3% of the measurements are in the TCD sensor range, assuming a sampler flow rate of 8 cubic feet per minute. For sites with less than 91% CH $_4$ , only 1.5% of the measurements are in the TCD range. BHFS, Bacharach HiFlow Sampler; NG, natural gas; TCD, thermal conductivity detector.

which point the sampler would need to transition to the thermal conductivity sensor to allow for accurate measurements. For sites with  ${
m CH_4}$  concentrations less than 91%, only four out of 259 measurements (1.5%) exceeded 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>), while for sites with CH<sub>4</sub> concentrations greater than 91%, 68 out of 510 measurements (13.3%) exceeded 0.4 scfm  $(0.7 \text{ m}^3 \text{ h}^{-1})$ . Consequently, there were almost nine times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH $_4$  (Fig. 2). If the sample flow rate were 6 scfm (10 m $^3$  h $^{-1}$ ) (due to a flow restriction or reduced battery power), the threshold for transition to the thermal conductivity range would be 0.3 scfm (0.5 m<sup>3</sup> h<sup>-1</sup>); this would still mean that there were almost seven times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH<sub>4</sub> than at sites with >91% CH<sub>4</sub>. Although it is well known that a small percentage of NG emission sources account for most of the total emissions from any given population [9, 15, 25], it is unlikely that almost all the significant emitters at NG production sites would occur only at sites with well head gas compositions >91% CH, It is also unlikely that the emission rates of all of the source categories surveyed by [1], which had diverse emission mechanisms such as equipment leaks, pneumatic controllers, chemical injection pumps, and tanks, would all have a ceiling of ~0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) at sites with lower wellhead gas CH₄ concentrations. Consequently, the low occurrence of high emitters at sites with lower wellhead gas CH<sub>4</sub> concentrations in [1] indicates that sensor transition failure occurred at sites with CH<sub>4</sub> content <91% and is consistent with the BHFS sensor failure found by Howard et al. [10].

### Alternative Theories for the Emission Rate Pattern

Other possible causes of the emission rate pattern in the UT BHFS measurements were considered, including: regional operating differences at production sites; lighter gas densities resulting in higher emission rates; and improved detection of emissions by auditory, visual, and olfactory (AVO, e.g., [24]) methods at sites with heavier hydrocarbon concentrations.

### Regional operating differences

Allen et al. [1] point out that air pollution regulations in Colorado which required installation of low bleed pneumatic devices in ozone nonattainment areas after 2009 might have led to lower emission rates in the Rocky Mountain region, which also had the lowest average concentration of  ${\rm CH_4}$  in the wellhead gas. However, if the

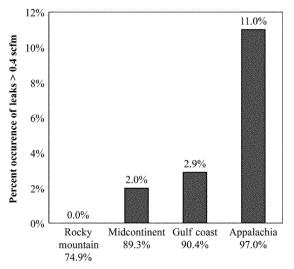
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UT Study Underestimates Methane Emissions

Rocky Mountain region is removed from the analysis, the occurrence of emitters >0.4 scfm (0.7 m³ h^-1) at sites with wellhead gas <91% CH<sub>4</sub> was still only four out of 129 measurements (3.1%), while for sites with CH<sub>4</sub> concentrations greater than 91%, there remain 68 out of 510 measurements (13.3%) that exceeded 0.4 scfm (0.7 m³ h^-1) (there were no Rocky Mountain sites with CH<sub>4</sub> >91%). Consequently, even if the Rocky Mountain region is removed from consideration, the occurrence of emitters >0.4 scfm (0.7 m³ h^-1) was almost four times less at sites with less than 91% CH<sub>4</sub> than at sites with greater than 91% CH<sub>4</sub>, so air quality regulations in Colorado do not appear to be the cause of the emission rate trend shown in Figure 2.

Beyond air pollution regulations, other unknown regional operating practices unrelated to  ${\rm CH_4}$  concentration might coincidentally cause the apparent relationship of site  ${\rm CH_4}$  concentrations with the occurrence of high emitters. However, as shown in Figure 3, the increase in leaks >0.4 scfm  $(0.7~{\rm m^3~h^{-1}})$  directly correlates with the increase in the average regional  ${\rm CH_4}$  concentration. Because there are four regions and two variables (site  ${\rm CH_4}$  concentration and the percent of leaks >0.4 scfm  $[0.7~{\rm m^3~h^{-1}}]$ ), the likelihood that regional operating characteristics would coincidentally cause the increase in occurrence of leaks >0.4 scfm  $(0.7~{\rm m^3~h^{-1}})$  to mirror the increasing regional site  ${\rm CH_4}$  concentration is only one in 24 (four factorial), or ~4%.



Region and average wellhead CH<sub>4</sub> concentration

Figure 3. Occurrence of equipment leaks >0.4 scfm in each region of the [1] equipment leak data set. The odds of the occurrence of leaks >0.4 scfm being positively correlated with site CH <sub>4</sub> concentration are one in 24, which makes it unlikely this trend is due to regional operating effects.

Other known operating characteristics of the regions, such as average site pressure and average site age, are not related to the occurrence of equipment leaks >0.4 scfm (0.7  $\rm m^3~h^{-1})$ : average site pressures show no correlation, and average site age is negatively correlated with the occurrence of equipment leaks >0.4 scfm (0.7  $\rm m^3~h^{-1})$ .

Another argument against regional differences comes from the air quality study conducted by the City of Fort Worth ([6]; or the Ft. Worth study). Ft. Worth is part of the Mid-Continent region defined by [1], where the occurrence of equipment leaks only (as opposed to all BHFS measurement categories) >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) observed by [1] was 2.0% of the total equipment leaks in that region. However, equipment leaks >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) were 9.9% of the equipment leaks measured in the Ft. Worth study. This was determined using the Ft. Worth study categories of valves and connectors; their remaining category of "other", which included pneumatic control devices, had an even higher occurrence of sources >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) of 27.0%. Previous work [10] has shown that although sensor transition failure likely occurred in the Ft. Worth study, these incidents were limited compared to those in [1]. Consequently, the much lower occurrence of leaks >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) in the Mid-Continent region in [1] compared to the Ft. Worth study indicates that sensor transition failure was responsible for the low occurrence of emitters < 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) as opposed to regional differences.

### Gas density

Wellhead gas with a lower  $\mathrm{CH_4}$  and a greater heavier hydrocarbon content will be denser than gas with higher  $\mathrm{CH_4}$  content. Since gas flow through an opening is inversely related to the square root of the gas density, streams with lower  $\mathrm{CH_4}$  content would have a lower flow rate if all other conditions were the same. However, this would cause at most a 20% decrease for the lowest  $\mathrm{CH_4}$ /highest heavier hydrocarbon streams compared to the highest  $\mathrm{CH_4}$ /lowest heavier hydrocarbon streams observed in the UT study. This would also result in a gradual increase in emissions as  $\mathrm{CH_4}$  content increased, as opposed to the dramatic increase in emissions observed over a very narrow range of  $\mathrm{CH_4}$  concentrations (Fig. 2).

### **AVO** detection

AVO methods might improve for gas streams with a greater proportion of heavier hydrocarbons, since those streams would have greater odor and might leave more visible residue near a leak. However, Figure 4 presents the occurrence of emitters >0.4 scfm (0.7 m³ h⁻¹) as a function of site CH<sub>4</sub> concentrations in the Appalachia

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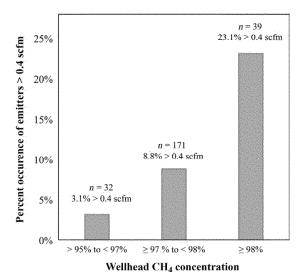


Figure 4. Occurrence of emitters >0.4 scfm as a function of site wellhead gas composition in [1] for the Appalachia region. An emission rate of greater than 0.4scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of 8scfm. The dramatic increase in emitters >0.4scfm over a narrow concentration range argues against the possibility that auditory, visual, and olfactory leak detection is the cause of the emission rate pattern seen in the [1] data set.

region alone. This region had the highest average CH<sub>4</sub> concentration in wellhead gas of any of the regions sampled in [1]. As seen in Figure 4, even over a very narrow range of site  $CH_4$  concentrations (from 95% to >98%  $CH_{A}$ ), there is a dramatic increase in emitters >0.4 scfm  $(0.7 \text{ m}^3 \text{ h}^{-1})$  with increasing CH<sub>4</sub> concentration. It is unlikely that AVO methods would become so much more efficient over such a narrow range of high CH 4 concentrations where the gas streams are likely odorless and would leave little residue. This dramatic increase in high emitters at sites with high CH<sub>4</sub> concentrations within the Appalachia region alone also argues against the previously discussed regional operating differences hypothesis in general, since this trend is within a single region. Additionally, although the Rocky Mountain region surveyed by UT [1] had the lowest average site CH<sub>4</sub> concentration (74.9%) and heaviest hydrocarbon content, it actually had the highest number of equipment leaks (of any size) per well of all the regions, and there were 25% more leaks per well in that region than in the Appalachia region, which had the highest average site CH<sub>4</sub> concentration (97.0%) and therefore the lowest heavier hydrocarbon content. If AVO methods were more effective due to the presence of heavier hydrocarbons, it seems unlikely the region with the heaviest hydrocarbon concentrations would have the highest rate of overall leak occurrences.

### Field Testing of the UT BHFS

Because the trend in the [1] data was consistent with sensor transition failure in the BHFS and no other explanation seemed plausible, I partnered with UT to test the sampler used by [1]. During that field program, the UT sampler had a version of firmware earlier than version 3.03, and older firmware versions have been shown to exhibit sensor transition failure [10]. However, the possible effect of the sampler's firmware version on the sensor failure was not known before this testing of the UT sampler, and at the time of my testing its firmware had been upgraded to a custom version (3.04).

As previously explained, the BHFS uses a catalytic oxidation sensor to measure sample stream concentrations from 0% to  $\sim\!5\%$  NG, and a thermal conductivity sensor for concentrations from  $\sim\!5\%$  to 100% NG. The catalytic oxidation sensor is typically calibrated with 2.5% CH $_4$  in air and the thermal conductivity sensor is calibrated with 100% CH $_4$  [4]. The manufacturer recommends sensor calibration every 30 days, a process which adjusts the response of the instrument. The calibration may also be checked ("bump-tested") periodically by the user, which does not adjust the instrument response. It is important to note that the description of the BHFS sensor operation in the supplemental information of [1] is incorrect, as they state that:

[A] portion of the sample is drawn from the manifold and directed to a combustibles sensor that measures the sample's methane concentration in the range of 0.05–100% gas by volume. The combustibles sensor consists of a catalytic oxidizer, designed to convert all sampled hydrocarbons to  $\rm CO_2$  and water. A thermal conductivity sensor is then used to determine  $\rm CO_2$  concentration.

However, the BHFS manual [4] clearly states that the catalytic oxidation sensor is used to measure concentrations from 0% to 5%  $\rm CH_4$  and the thermal conductivity sensor from 5% to 100%  $\rm CH_4$ . This is a critical distinction because understanding that the BHFS uses a different sensor for each range and that it must transition from the catalytic oxidation sensor to the thermal conductivity sensor in order to conduct accurate measurements is critical to understanding the problem of sensor transition failure.

I initially conducted field testing of the UT sampler in conjunction with the UT team at a NG production site with a wellhead gas CH<sub>4</sub> concentration of 90.8%. NG composition analysis (via gas chromatograph-flameionization detector) of wellhead gas at this site was conducted by the host company just prior to the sampler testing. The tests were conducted by metering known flow rates of NG into the BHFS inlets through a rotameter (King Instrument Company, Garden Grove, CA; 0–10 scfm air

scale). The sample concentration indicated by the internal BHFS sensor was recorded and compared to an external gas concentration monitor used to measure the actual NG concentration at the sampler exhaust (Bascom-Turner Gas Sentry CGA 201, Norwood, MA). The Gas Sentry unit was calibrated with 2.5% and 100%  ${\rm CH_4}$  prior to the testing; exhaust concentrations measured using this unit agreed with concentrations calculated using the sampler flowrate and amount of NG metered into the inlet to within an average of  $\pm 6\%$ .

This field testing was conducted in March of 2014 and is described by [10]; the UT sampler is identified therein as BHFS No. 3. At the time of this testing, the UT BHFS had firmwareVersion 3.04 (September 2013); this sampler had been calibrated 2 weeks prior to the fieldtest and had been used for emission measurements at production sites since that time. The response of the sensors was checked ("bump-tested") by the UT field team but not calibrated prior to the start of testing. This was apparently consistent with the UT fieldprogram methodology: the sampler had been used for measurements with only sensor bump tests, but without the actual calibration unless the sensors failed the bump tests (as was acceptable according to the manufacturer's guidelines) during their ongoing field measurement program and was provided to me for these measurements "ready for testing".

Although the UT sampler's internal sensors initially measured the sample concentration correctly, after ~20 min of testing the sampler's sensors failed to transition from the catalytic oxidation scale (<5% NG) to the thermal conductivity scale (>5% NG), resulting in sample concentration measurements that were 11-57 times lower than the actual sample concentration (Fig. 5). Because sample concentration is directly used to calculate emission measurements made by the sampler, this would result in emission measurements that are too low. After this sensor transition failure occurred, the UT BHFS was calibrated (not simply "bump-tested") and thereafter did not exhibit any further sensor transition failures even during a second day of testing at sites with wellhead CH<sub>4</sub> concentrations as low as 77%. Two other BHFS that were not part of the UT program were also tested using the same procedure: these instruments had the most updated firmware commercially available (Version 3.03) and were put through an actual calibration sequence by the instrument distributor's representative prior to any testing. Neither of these instruments exhibited sensor transition failure at any of the sites. These results combined with the sensor transition failure previously observed in instruments with earlier versions of firmware suggest that the combination of updated firmware and frequent actual calibrations might reduce sensor failure, although this has not been proved conclusively [10, 11].

6

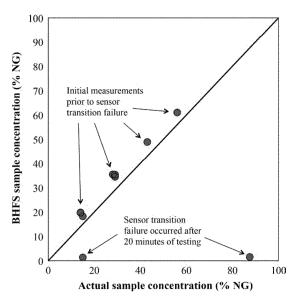


Figure 5. Performance of the BHFS used during the [1] study with NG composed of 90.8% CH<sub>4</sub>; instrument firmware had been upgraded to version 3.04 after that study but before this testing; calibration was 2 weeks old. Sensor transition failure set in after ~20min of testing; this failure was eliminated once the BHFS was put through a calibration sequence (as opposed to just a response test). BHFS, Bacharach HiFlow Sampler: NG, natural gas.

The UT recently published a follow-up study of pneumatic device emissions [2]. As part of this work, Allen et al. [2] conducted laboratory testing of the UT BHFS by making controlled releases of both 100% CH<sub>4</sub> and a test gas of 70.5% CH<sub>4</sub> mixed with heavier hydrocarbons into the UT BHFS and did not report any sensor transition failures during these tests, but during this laboratory testing the sampler (with the updated firmware version 3.04) was calibrated (not 'bump-tested") immediately prior to any testing. Consequently, the absence of sensor failure during their laboratory testing is consistent with the results observed during the March 2014 field tests, where calibrating the instrument eliminated the sensor failure.

Allen et al. [3] have suggested that the protocol during their field campaign was to check the calibration of the UT BHFS anytime it was turned on and that not following this protocol led to the sensor transition failure observed during this testing. However, in this instance, the sensor failure occurred both prior to and after the instrument was restarted. Additionally, the UT team observing the testing process did not suggest a calibration check when the instrument was turned back on for further testing. It was only after the sensor failure was observed that they checked and calibrated the instrument, so it

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does not appear that their protocol was to check the instrument calibration anytime it was turned on.

In summary, because the firmwarefor the UT sampler was updated prior to this testing (and therefore not the same as the version used during the UT field campaign [1]), and updated firmware may be a factor in reducing sensor failure, it is not expected that these test results are representative of how frequently sensor transition failure might have occurred during the UT study [1]. However, these results do clearly demonstrate that sensor transition failure could occur while using the UT BHFS.

### Comparison With Other Pneumatic Device Studies

Two other recent studies have measured emission rates from pneumatic devices by installing meters into the supply gas lines of the devices, as opposed to measuring emissions using the BHFS as was done by Allen et al. [1]. Prasino [22] used the meter installation technique to study emissions from pneumatic controllers in British Columbia, and the UT follow-up study [2] installed meters to measure emission rates from pneumatics in the four regions surveyed in the previous UT study [1].

Unfortunately, it is not possible to compare the pneumatic device emission factors from [1] to those from either the Prasino study, or from [2], because even though [1] sought to randomly sample pneumatic devices, the result was clearly an emitter data set (measurements focused on pneumatic devices that were emitting), while the Prasino data set was made with a random selection of devices and [2] made comprehensive measurements of all devices that could be measured safely at each site. This difference can be demonstrated by comparing the percentage of emitting intermittent pneumatic devices occurring in [1] to that in [2]. In [1], 95.3% (123 out of 129 intermittent devices) were greater than zero, with the smallest nonzero emitter equal to 0.12 scfh  $(0.0034 \text{ m}^3 \text{ h}^{-1})$ . In [2], only 57.5% (184 out of 320) intermittent devices) were greater than zero. This percentage of nonzero measurements drops further if the lowest nonzero emitter (0.12 scfh; 0.0034 m<sup>3</sup> h<sup>-1</sup>) observed by [1] is used as a threshold, in which case only 21.3% (68 out of 320) would be considered emitters. Since this threshold of 0.12 scfh (0.0034 m<sup>3</sup> h<sup>-1</sup>) is 25 times lower than the typical minimum range of the Fox FT2A meters by [2], the reported emitters below this threshold are most likely instrument noise caused by the meter's thermal elements inducing convection currents [7].

Consequently, although the intent of [1] was to survey randomly selected devices, their approach actually resulted in a data set comprised almost exclusively of emitting devices; this possibility is acknowledged by [2]. Therefore,

average emissions and emission factors for pneumatic devices calculated from [1] cannot be compared to those calculated from data collected by random or comprehensive sampling, such as presented in [22] or [2], because the emitter data set removes almost all the zero emitters and would result in much higher average emissions.

However, both [1] and [2] provide the  $\mathrm{CH_4}$  composition of the wellhead gas at the sites surveyed. This allows a comparison of emission rate patterns as a function of  $\mathrm{CH_4}$  concentration between devices measured by the BHFS [1] and by installed meters [2]. If the scarcity of high emitters measured by BHFS at sites with lower  $\mathrm{CH_4}$  concentrations in the initial UT study [1] was not an artifact caused by sensor transition failure, then the same concentration pattern should be present whether measured by the BHFS or by installed meters.

For this analysis, I removed the Rocky Mountain region to eliminate any bias from current or impending regulations that might have affected emission rates. Additionally, I focused on emissions from intermittent pneumatics because that provides the most complete data set from the two studies. Finally, as noted previously, the pneumatic device measurements from [1] apparently focused on emitting devices, whereas the devices surveyed in [2] were sampled as comprehensively as possible so the occurrences of high emitters in each study cannot be directly compared. Consequently, it is the ratio of the occurrences of high emitters at low CH<sub>4</sub> sites compared to high CH<sub>4</sub> sites within each study that must be compared.

As seen in Table 1, when measured by [1] via BHFS, the occurrence of emitters >0.4 scfm (0.7 m³ h $^{-1}$ ) (on a percentage basis) at sites with wellhead gas compositions <91% CH $_4$  is almost a factor of five less than at sites with CH $_4$  >91%, consistent with BHFS sensor failure. Conversely, when measured via installed meters [2], the occurrence of emitters >0.4 scfm (0.7 m³ h $^{-1}$ ) at sites with wellhead gas compositions <91% CH $_4$  is almost a factor of three higher than at sites with >91% CH $_4$ , indicating a complete reversal in this trend. This stark difference between BHFS measurements and installed meter measurements corroborates that the scarcity of high emitters at sites with lower wellhead gas CH $_4$  content present in [1] was an artifact due to sensor failure in the BHFS.

## Focused Analysis of the UT Study Equipment Leaks

In order to better understand the threshold of wellhead gas CH<sub>4</sub> concentrations at which sensor transition failure might occur, I conducted further analysis focused only on the equipment leak measurements in [1]. Equipment leaks were targeted because they are expected to be short term, steady state measurements, whereas emissions

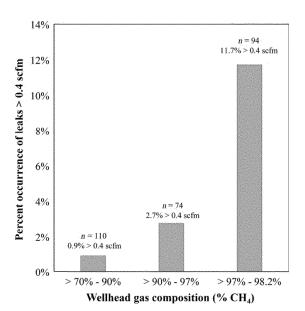
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Table 1. Occurrence of intermittent pneumatic device high emitters as a function of wellhead gas composition, measured by Bacharach Hi- Flow Sampler (BHFS) and installed meters (Rocky Mountain region excluded).

	No. of devices measured	No. of devices with emissions >0.4 scfm	% of devices with emissions >0.4 scfm
Allen et al. [1] (Measured by BHFS sampler)			
Wellhead gas composition >91% CH₄	85	28	32.9
Wellhead gas composition <91% CH <sub>2</sub>	44	3	6.8
Ratio of frequency of high emitters at sites with well wellhead gas compositions >91% CH <sub>4</sub>	head gas compositions <91% Ch	ቲ to sites with	0.21
Allen et al. [2] (Measured by installed meters)			
Wellhead gas composition >91% CH₄	106	3	2.8
Wellhead gas composition <91% CH <sub>2</sub>	97	8	8.2
Ratio of frequency of high emitters at sites with well wellhead gas compositions >91% CH <sub>4</sub>	head gas compositions <91% CF	ዛ <sub>4</sub> to sites with	2.9

reported from pneumatic devices and chemical injection pumps are likely to be an average of several measurements, and emissions from tanks may have an NG composition different from the reported wellhead composition.

Figure 6 presents the occurrence of equipment leaks in [1] that are >0.4 scfm (0.7 m³ h $^{-1}$ ) as a function of site CH $_4$  concentrations. At sites with gas compositions of >97% CH $_4$ , 11.7% of the leaks were >0.4 scfm (0.7 m³ h $^{-1}$ ). At sites with wellhead compositions between 90% and 97% CH $_4$ , only 2.7% of the leaks were >0.4 scfm



**Figure 6.** Occurrence of equipment leaks >0.4scfm as a function of site well head gas CH <sub>4</sub> content in the [1] study. Leaks >0.4 scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of &cfm. The large increase in the occurrence of leaks >0.4 scfm at sites with CH<sub>4</sub> content >97% indicates sensor transition failure below that threshold.

(0.7 m³ h⁻¹), and this occurrence dropped to less than 1% at sites with wellhead gas compositions of <90% CH₄, indicating that the sampler's ability to measure leaks >0.4 scfm (0.7 m³ h⁻¹) declined dramatically with decreasing concentrations of CH₄ in the wellhead gas (Fig. 6). This analysis indicates the BHFS may underreport emitters >0.4 scfm (0.7 m³ h⁻¹) even when making measurements of NG streams with CH₄ content up to 97%, and provides a valuable refinement of the possible CH  $_4$  concentration threshold where sensor failure may occur, since the highest CH₄ wellhead content available for direct field testing of the BHFS was only 91.8%.

### Comparison of the UT Study Downwind Tracer Ratio Measurements to On-Site Measurements

Allen et al. [1] also made emission measurements using a downwind tracer ratio method at 19 sites for comparison to their on-site measurements. Their emissions from onsite measurements were calculated by using direct measurements of equipment leaks and pneumatic devices that were made by the UT team combined with estimates of emissions from any sources at the well pad that were not measured. These unmeasured sources included all tanks and compressors (compressors were a small source in comparison to all other sources) as well as any pneumatics that was not directly measured during the site survey. For CH<sub>4</sub> emissions from tanks and compressors, the authors used "standard emissions estimation methods" [1]. For pneumatic devices that were not surveyed, they applied their own emission factors based on the measurements of pneumatic devices collected during the UT study.

The tracer ratio measurements were made by releasing a tracer gas at a known rate to simulate the emissions from the site being measured. Simultaneous downwind measurements were then made of the concentrations of both the tracer gas and  $CH_4$ , and then the emission rate

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of  $\mathrm{CH_4}$  was calculated after correcting for background  $\mathrm{CH_4}$  and tracer concentrations. The tracer ratio method allows for the calculation of  $\mathrm{CH_4}$  emissions from the entire production site by accounting for the dilution of  $\mathrm{CH_4}$  as it is transported into the atmosphere from the source to the receptor.

In summarizing their tracer ratio measurements, [1] state: "For the production sites, emissions estimated based on the downwind measurements were also comparable to total on-site measurements; however, because the total on-site emissions were determined by using a combination of measurements and estimation methods, it is difficult to use downwind measurements to confirm the direct source measurements." However, upon further examination, I found that the downwind tracer measurements do in fact indicate the occurrence of sensor transition failure in their BHFS measurements.

Table 2 summarizes the characteristics of the sites surveyed by [1] using both the BHFS and the tracer ratio method. As described above, the on-site total is a combination of the measurements made by BHFS and estimates for any sources not actually measured by the UT team. I calculated the ratio of actual BHFS measurements to

the total reported on-site emissions (estimated and measured) using the supplemental information provided by [1]. Actual measured emissions ranged from 1% to 79% of the total reported on-site emissions and the on-site total emissions range from 13% to 3500% of the downwind tracer ratio measurements (Table 2).

Table 3 compares the tracer ratio measurements to the on-site emissions, categorized by  ${\rm CH_4}$  content in the well-head gas and by the fraction of actual BHFS measurements that comprise the on-site emissions. As shown in Table 3, when comparing all sites without separating them into these categories, the total of the tracer ratio measurements does agree closely to the on-site emissions, as [1] concluded. However, four of the sites had wellhead gas compositions of  $\geq$ 97%  ${\rm CH_4}$ , at which the BHFS would be expected to make accurate measurements. The remaining 15 sites had wellhead gas compositions of <82%  ${\rm CH_4}$ , at which sensor transition failure might occur and the BHFS would underreport emissions measurements.

Once the sites are categorized by these wellhead gas compositions, a deficit between the on-site emissions and the tracer ratio measurements appears in sites with lower  $CH_A$  concentrations, and this deficit becomes more

Table 2. Sites surveyed by Allen et al. [1] using both Bacharach Hi-Flow Sampler (BHFS) and downwind tracer methods.

Tracer site name <sup>1</sup>	BHFS site name <sup>1</sup>	Wellhead gas CH <sub>4</sub> concentration (%)	On-site total <sup>2</sup> (BHFS measurements and estimates) (scfm CH <sub>4</sub> )	BHFS measure- ments/on-site total <sup>3</sup>	Leaks measured by BHFS/on-site total <sup>3</sup>	Tracer ratio emission rate (scfm CH <sub>4</sub> )	On-site total/ tracer ratio emission rate
MC-1	MC-1	70.9	1.89	0.12	0.12	2.32	0.815
MC-2	MC-14	78.1	0.99	0.34	0.01	2.00	0.495
MC-3	MC-20	77.2	1.63	0.45	0.18	2.95	0.552
MC-4	MC-5	74.2	2.31	0.19	0.14	3.36	0.687
MC-5	MC-16	79.3	1.85	0.56	0.18	4.16	0.445
RM-1	RM-7	81.9	0.22	0.11	0.09	0.584	0.368
RM-2	RM-8	74.5	4.43	0.02	0.02	1.70	2.60
RM-3	RM-1	76.4	0.13	0.67	0.69	0.442	0.303
RM-4	RM-3	74.9	0.11	0.21	0.00	0.839	0.137
RM-5	RM-2	74.5	0.09	0.35	0.33	0.240	0.392
RM-6	RM-5	74.5	0.74	0.41	0.42	0.421	1.75
RM-7	RM-14	74.5	0.27	0.26	0.26	0.368	0.736
RM-8	RM-19	76.2	0.29	0.82	0.79	1.08	0.266
RM-9	RM-12	74.5	0.38	0.05	0.05	0.864	0.436
RM-10	RM-4	76.2	2.86	0.01	0.00	0.080	35.7
AP-2	AP-23	97.6	1.28	0.68	0.35	0.270	4.74
AP-3	AP-43	97.0	4.75	0.62	0.59	4.12	1.15
AP-4	AP-37	97.0	1.36	0.44	0.42	0.709	1.92
AP-5	AP-18	97.0	0.39	0.74	0.69	0.288	1.37

<sup>&</sup>lt;sup>1</sup>MC, Midcontinent; RM, Rocky Mountain; AP, Appalachia. Different site numbers were used to identify the same sites in the [1] supplemental information depending on whether BHFS or tracer ratio measurements were under discussion.

<sup>&</sup>lt;sup>2</sup>On-site totals were calculated by [1] by combining measurements made by the BHFS with estimates of any sources not measured; these estimates were made using mathematical models for tanks as well as emission factors for compressors and any pneumatic controllers not directly measured. 
<sup>3</sup>Calculated by this author from [1] supplemental information.

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pronounced as the amount of the on-site emissions actually measured by the BHFS becomes a larger fraction of the total on-site emissions (measured and estimated). As seen in Table 3, for the high CH<sub>4</sub> sites where the sampler should function properly, the on-site measurements and estimates exceed the tracer measurements, but approach a ratio of one (complete agreement) as the amount of actual measurements increases. For the two sites with wellhead gas compositions ≥97% where the measured equipment leaks (which should produce steady emissions as compared to pneumatic devices which might be intermittent) averaged 64% of the total on-site measurements and estimates, the on-site total still exceeds the tracer measurements but are within 17% (Table 3). However, for the sites with wellhead gas  ${\rm CH_4}$  concentrations <82%, there is a clear trend of increasing deficit of the on-site emissions compared to the tracer ratio measurements as the actual BHFS measurements become a larger part of the on-site total. For instance, for the nine sites with at least 20% of on-site emissions from BHFS measurements (for an average of 45% of the total on-site emissions measured by the BHFS), the on-site emissions are only 49% of the tracer measurements (Table 3). For the two sites that had greater than 67% of on-site emissions data actually measured by the BHFS (for an average of 75% of on-site emissions data measured by the BHFS), the on-site emissions are only 28% of the tracer measurements (Table 3).

Comparing the on-site data to the downwind tracer measurements provides two valuable insights. First, there were six sites in the Rocky Mountain region for which at least 20% of the on-site emissions were measured by the BHFS (for an average of 45% actual BHFS measurements) (Table 2). For these six sites, the on-site emissions average 48% of the tracer data. For the two sites in this

region with at least 67% of on-site emissions from actual BHFS measurements (and with BHFS measurements averaging 75% of the total on-site data), the on-site emissions were only 28% of the tracer measurements (Table 2). This provides clear evidence that the sampler actually did fail in the Rocky Mountain region, as opposed to any possible regional differences (discussed previously) that might have created an emission pattern of no high emitters at sites with lower  ${\rm CH_4}$  concentrations in the wellhead gas.

Additionally, the tracer measurements provide a method to estimate the magnitude of errors introduced in the data collected by [1] due to BHFS sensor transition failure. For all of the sites with wellhead gas compositions ≥97% CH<sub>4</sub> (where the sampler should operate correctly), the emission rates determined by on-site measurements exceeded those determined by the downwind tracer ratio measurements. Assuming that the tracer method accurately measured the total emissions from the sites surveyed (e.g., [8, 15, 16]), I concluded that the methods used in [1] overestimated the on-site sources that were not directly measured. Therefore, I calculated the error in BHFS measurements at sites with low CH<sub>4</sub> wellhead gas composition by assuming the tracer ratio measurements are correct. I have also assumed for this analysis that the estimates of any onsite sources made by [1] are also correct, even though the tracer data indicate they may be too high, because this is conservative in the sense that correcting for this overestimate would increase the BHFS error calculated below. Given these assumptions, subtracting the on-site estimated emissions from the tracer ratio emissions gives the expected measurement total that should have been reported from the BHFS measurements. Comparing this expected measurement total to the actual

Table 3. Comparison of on-site measurements to tracer ratio measurements made by Allen et al. [1] categorized by wellhead gas CH<sub>4</sub> concentration.

Site category (number of sites in parentheses)	Average percentage of on-site emissions reported by BHFS	Total on-site emissions (reported by BHFS and estimated) (scfm CH <sub>4</sub> )	Total emissions measured by tracer (scfm CH <sub>4</sub> )	Ratio of on-site emissions to emissions measured by tracer
All sites (19)	37	26.0	26.8	0.97
Sites where BHFS measurements are expected	to be accurate (wellhead	Igas composition ≥97% Ch	<u>4</u> )	
All sites (4)	62	7.78	5.39	1.44
Sites with >50% BHFS measurements (3)	68	6.42	4.68	1.37
Sites with >50% equipment leaks (2)	64 (equipment leaks/on-site total)	5.14	4.41	1.17
Sites where BHFS measurements are expected	to underreport high emi	tters (wellhead gas compos	ition <82% CH <sub>A</sub> )	
All sites (15)	28	18.2	21.4	0.85
Sites with ≥5% BHFS measurements (13)	35	10.9	19.6	0.56
Sites with ≥20% BHFS measurements (9)	45	6.10	12.5	0.49
Sites with >50% BHFS measurements (3)	69	2.27	5.68	0.40
Sites with >67% BHFS measurements (2)	75	0.42	1.52	0.28

BHFS, Bacharach Hi-Flow Sampler.

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measurement total reported by the BHFS provides an estimate of the error in BHFS measurements made by Allen et al. [1].

Table 4 presents the results of this analysis, and shows that for the 13 sites with wellhead gas compositions <82% CH<sub>4</sub> and with at least 5% actual BHFS measurements (with an average of 35% of emission sources measured by BHFS; bottom half of Table 3), the actual measurement total of the BHFS is less than one-third of the expected total, and this appears consistent as sites with greater fractions of actual BHFS measurements are examined. For these sites, the emission rates for equipment leaks and pneumatics devices presented by [1] are approximately equal, so it is not possible to assign a larger error to one category or another. Additionally, the errors introduced by the sensor failure would be expected to vary from site to site depending on how many emitters were present with emission rates exceeding the sensor transition threshold ceiling. Nevertheless, for these 13 sites, the BHFS underreported emissions for equipment leaks and pneumatic devices on average by more than a factor of 3 (Table 4).

Although the magnitude of error due to BHFS sensor failure is not known for all the sites in [1], the tracer ratio measurements make clear that the BHFS measurements for sites with lower CH<sub>4</sub> content in the wellhead gas could be at least a factor of three too low. More precise estimates of errors in [1] are not possible because of the nature of the sensor failure. Unlike a simple calibration error, for which it might be possible to correct, when sensor transition failure occurs, it is not possible to know for any particular measurement if the failure has occurred, and if it has, what the resulting error was, since the reported emission rates could range from 20% to two orders of magnitude too low.

### **Implications**

Sensor transition failure is clearly apparent in the BHFS measurements made in the UT study by Allen et al. [1], as evidenced by the rare occurrence of high emitters at sites with lower CH<sub>4</sub> (<91%) content in the wellhead gas. The occurrence of this sensor transition failure was corroborated by fieldtests of the UT BHFS during which it exhibited this sensor failure, as well as by tracer ratio measurements made by [1] at a subset of sites with lower wellhead gas CH4 concentrations. At this subset of sites, the tracer ratio measurements indicate that the BHFS measurements were too low by at least a factor of three. Because BHFS measurements were the basis of 98% of the inventory developed by [1] using their own measurements (and 41% of their total compiled inventory), the inventory clearly underestimates CH<sub>4</sub> emissions from production sites. However, the extent of this error is difficult to estimate because the underreporting of emission rates due to BHFS sensor transition failure at any given site would vary depending on sampler performance and on how many high emitters were present at that site. Estimating this error is further complicated by the fact that the data set collected for pneumatic devices by [1] was an emitter data set; this might offset the effect of underreported high emitters in their pneumatic device emission factors. Finally, although real differences may exist in regional emission rates, the UT data set [1] should not be used to characterize them because the occurrence of sensor failure clearly varied between regions due to variations in wellhead CH₄ compositions, which may mask any actual regional differences that existed.

Although the performance of the BHFS may vary between instruments or with sensor age or calibration vintage, this analysis of the [1] data set shows that measurements made using a BHFS for NG streams with  $\mathrm{CH_4}$  content

**Table 4.** Estimation of underreporting in Allen et al. [1] BHFS measurements of CH<sub>4</sub> emission rates at sites with low CH<sub>4</sub> well head gas composition (<82%), using downwind tracer measurements (from Table 3).

Minimum percentage of on-site emissions reported by BHFS	Average percentage of on-site emissions reported by BHFS	No. of sites	Total emissions measured by tracer (scfm CH <sub>4</sub> )	On-site emissions estimated by UT (excludes BHFS measure- ments) (scfm CH <sub>4</sub> )	Expected BHFS measurement total (tracer – on-site estimates) (scfm CH <sub>4</sub> )	Emissions reported by BHFS (scfm CH <sub>4</sub> )	Ratio of reported BHFS to expected BHFS
≥5	35	13	19.63	7.09	12.54	3.81	0.30
≥20	45	9	12.50	3.34	9.16	2.76	0.30
>50	69	3	5.68	0.71	4.97	1.56	0.31
>67	75	2	1.52	0.11	1.42	0.31	0.22

BHFS, Bacharach Hi-Flow Sampler; UT, University of Texas.

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up to 97% could lead to severe underreporting of NG leaks. That this failure can occur at such high  $\mathrm{CH_4}$  concentrations, which are close to the higher end of those found in transmission and distribution systems, indicates that past measurements in all segments of the NG supply chain could have been affected by this problem. Because the BHFS sensor transition failure phenomenon is not fully understood, it is not known how much this error may have affected past measurements of  $\mathrm{CH_4}$  emission rates. Two factors preclude this: first, the performance of any individual BHFS may vary, and second, once sensor transition failure occurs, there is no way to determine the magnitude of the measurement error in the absence of an independent flux or concentration measurement.

If BHFS sensor transition failure has occurred during industry monitoring at transmission, storage, and processing compressor stations where the BHFS is approved for leak measurements mandated by the USEPA Subpart W Greenhouse Gas Reporting Program (GHGRP) [23], then these errors could be larger than those observed at production sites. Leaks at transmission, storage, and processing compressor stations commonly exceed 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) (the approximate threshold for BHFS sensor transition failure) and in some cases may range from 10 to over 100 scfm. Because the largest 10% of leaks typically account for 60-85% of the total leak rate at a given facility [9, 25], sensor transition failure in the BHFS could bias CH4 emission inventories compiled by the USEPA GHGRP substantially low since the most significant leaks could be underreported. Additionally, leak measurements using the BHFS may be used to guide repair decisions at NG facilities, and underreporting of leaks could compromise safety if large leaks remain unrepaired as a result.

Finally, it is important to note that the BHFS sensor failure in the UT study [1] went undetected in spite of the clear artifact that it created in the emission rate trend as a function of wellhead gas CH<sub>4</sub> content and even though the authors' own secondary measurements made by the downwind tracer ratio technique confirmed the BHFS sensor failure. That such an obvious problem could escape notice in this high profile, landmark study highlights the need for increased vigilance in all aspects of quality assurance for all CH<sub>4</sub> emission rate measurement programs.

### Acknowledgments

The author thanks Dave Allen (University of Texas at Austin) for making the UT BHFS available for field testing, and Adam Pacsi (University of Texas at Austin), Matt Harrison and Dave Maxwell (URS Corporation), and Tom Ferrara (Conestoga Rovers & Associates) for their assistance

with the field testing of the BHFS. This paper was substantially improved by the comments of three anonymous reviewers.

### **Conflict of Interest**

The author is the developer of high flowsampling technology (US Patent RE37, 403) and holds a license to use it for any purpose; however, he does not sell high flow samplers nor was he involved in the development of the Bacharach Hi-Flow Sampler.

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### **Energy Science & Engineering**

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# Response to "Comment on "University of Texas study underestimates national methane emissions inventory at natural gas production sites due to instrument sensor failure""

Journal:	ENERGY SCIENCE & ENGINEERING
Manuscript ID	Draft
Wiley - Manuscript type:	Response
Search Terms:	Environment, Natural gas, Safety
Abstract:	The authors of the University of Texas (UT) study dispute my analysis in "University of Texas study underestimates national methane emissions inventory at natural gas production sites due to instrument sensor failure" demonstrating that sensor transition failure affected their Bacharach Hi-Flow Sampler (BHFS) measurements at natural gas production sites. Although I addressed most of their arguments in the original paper, here I summarize the relevant evidence and also provide a simplified comparison of their downwind tracer measurements and on-site measurements. This comparison provides clear independent verification, using the authors' own data, that their BHFS measurements were too low at sites with lower methane content in the wellhead gas. Because the BHFS sensor failure presents a critical safety issue, and their incorrect defense of this work distracts from this problem, I call upon the authors and sponsors of the UT study to retract the UT BHFS measurement data ir order to ensure the safety of industry personnel and to protect the health of communities near oil and natural gas facilities.

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Dr. Allen and colleagues from the University of Texas (UT) (1) argue that sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS) did not affect their 2013 UT study (2) as I presented in (3). This is a welcome and critically important discussion because sensor failure in the BHFS may cause both underreporting of methane ( $CH_4$ ) emissions and underestimation of the health effects from air emissions at oil and natural gas (NG) facilities. Most importantly, however, the BHFS is also used to prioritize the repair of NG leaks, and if a large leak were not repaired because the BHFS underestimated it, this could lead to catastrophic component failure and/or explosion.

Although the rebuttal by (1) contends that the BHFS has been used since the 1990's, the BHFS has actually only been commercially available since 2003. High flow sampling measurements of NG leaks made prior to this were done with custom built instruments based on my design, which Bacharach, Inc. then developed into the BHFS. However, I am not affiliated with Bacharach, Inc. and I was not associated with the development of the BHFS.

The primary evidence of sensor failure is not the lack of high emitters in the UT BHFS data set (2) as stated by (1) but rather the direct experimental observance of this failure, which has been reported in (4) and (5), and, as summarized in (3), has been observed in four out of six samplers that were tested using NG with CH<sub>4</sub> content of < 91%. However, because the UT BHFS data set (2) contains measurements of several different types of sources with wide ranges of natural gas compositions, it provides a unique opportunity to evaluate the possibility that the occurrence of sensor failure might be widespread. It is certainly important to recognize that the BHFS measurements in (2) were biased low by sensor failure so that this data set is not relied upon to inform public policy. However, the much more important result of my analysis (3) of the UT BHFS data set is that sensor failure could indeed be widespread, since it appears to have occurred when measuring NG streams with CH<sub>4</sub> concentrations as high as 97%. This means that BHFS measurements throughout all sectors of the NG industry could be affected.

A third point of confusion is the contention by (1) that air pollution regulations in the Rocky Mountain region resulted in lower emission rates in that region, and that this explains the lack of high emitters at sites with lower  $CH_4$  content observed in their study because that region also had a lower  $CH_4$  content in the wellhead gas. Air pollution regulations might indeed result in lower emission rates in the Rocky Mountain region, but my analysis in (3) explains in detail that this is clearly not the cause of the scarcity of high emitters at sites with wellhead gas of lower  $CH_4$  content. To summarize, my analysis explains that:

- 1) Even when the Rocky Mountain region is excluded, there are still almost four times fewer high emitters at sites with wellhead NG compositions < 91% CH<sub>4</sub> than sites with > 91% CH<sub>4</sub>;
- 2) Pneumatic device emissions measured using flowmeters in a UT follow-up study (6) show a complete reversal of the pattern of pneumatic device emissions measured by BHFS in the UT study (2), i.e., when measured by flow meters, there was a larger occurrence of high emitters at sites with low well head gas CH<sub>4</sub> content;
- 3) Emission rates measured by BHFS reported by (2) within a single region Appalachia show a dramatic pattern of decreasing occurrence of high emitters as wellhead CH<sub>4</sub> concentration decreases over a narrow range from 98 to 95% CH<sub>4</sub>; and

4) Although the downwind tracer measurements (discussed in further detail below) made by (2) confirm that emission rates in the Rocky Mountain region were lower than other regions, these measurements also confirm that the BHFS measurements are too low at sites with low wellhead gas CH<sub>4</sub> content, even in the Rocky Mountain region.

It was also asserted by (1) that both field and laboratory testing showed little evidence of the sensor failure. As described in (3), I tested the sampler used in the UT study after the publication of their initial results in (2) in the presence of members of the UT field team and observed the sensor failure during this testing (4). This failure occurred even though the sampler had been upgraded to a new generation of firmware after it was used to conduct the measurements made during the initial UT study (2). After I conducted this field testing, I immediately interviewed two experienced BHFS technicians not associated with the UT team who reported that the new generation of firmware had eliminated problems in their samplers that caused leaks too be reported too low. Given the dramatic improvement in performance of samplers reported by these technicians using the updated generation of firmware, it is not surprising that the sensor failure only occurred sporadically in the UT sampler during the field tests and was not observed in their laboratory tests. Indeed, it is rather surprising that sensor failure occurred at all in a unit with updated firmware, although this highlights that the factors affecting sensor failure are still not well understood. I immediately relayed these reports of improved performance of samplers with updated software to the UT team in March of 2013, so the authors of (1) and (2) are well aware that the performance of the UT sampler could have been much worse when it was used for the original UT study (2), during which time it had older firmware. It is also interesting to note that during the March 2013 field testing, the UT team had a second BHFS that they did not allow me to test, stating that it had too many problems to make testing it worthwhile, although the nature of those problems was not specified.

The rebuttal (1) further asserts that the reason sensor transition failure occurred in the UT sampler during the field testing I conducted was that the proper UT calibration protocol was not followed. As I explained in (3), the UT team made no effort to conduct calibrations after the instrument was turned off and on but only did so after sensor failure was noted. Consequently, in contrast to what they have stated in (1), it does not appear that the UT protocol was to calibrate any time the instrument was turned on.

Allen and his colleagues (1) also state that because the average emission rates of pneumatic devices measured by flow meters in their follow-up study (6) are lower than those measured by their BHFS in (2), this disproves the possibility of sensor failure since sensor failure should cause the BHFS measurements to be lower. However, as I explained in (3), the pneumatic device data collected by BHFS (2) were clearly not a random sample but instead focused only on emitting devices and inadvertently excluded zero emission sources. This is one reason why average pneumatic device emission rates calculated from the BHFS data (2) are higher than those calculated from the flow meter data (6). Additionally, much of the pneumatic device data collected by flow meters (6) was likely biased low due to calibration problems. The authors of (6) only calibrated their meters before and after their field work, and claim in their supplemental information that they only became aware of a calibration problem with one meter during their post project calibration. However, as I reported in (7), I also tested the UT flow meters in March of 2013 while the measurements for the follow-up study (6) were ongoing, again in the presence of the UT field team. During these tests, one of their two primary meters indicated flow rates that were a factor of three lower than the actual flow rates released through the meters. Even

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after applying their post project calibration correction (6), the flow rates measured by this faulty meter during these tests would still be a factor of two lower than the actual flow rates. These two additional failures of quality assurance – the inadvertent exclusion of zero emitters from a supposedly random sample of devices in (2) and the inadequate calibration of flow meters in (6) – further highlight the need for dramatic improvements in greenhouse gas measurements programs.

Allen and colleagues (1) also maintain that infrared camera data showed no evidence that the BHFS did not accurately measure high emitters; however, there is ample evidence that infrared camera visualization cannot be currently used to quantify leaks. For instance, during the Ft. Worth Air Quality study (8), daily QA checks on the IR camera indicated variations in factors of up to 15 in the distance at which a known leak could be identified, much less quantified, under calm conditions. This large variability, even under calm conditions, demonstrates the huge uncertainty in trying to quantify emission rates with an IR camera, since any air movement near the leak would dramatically increase this variability.

Finally, their rebuttal (1) also states that my comparison (3) of the downwind tracer measurements to the on-site emissions measurements in the UT study (2) is "complex" and obscures the fact that the average emission rates from wells in the Rocky Mountain region were too small for the sensor failure to have occurred. In particular, they state: "The average per well emissions in the Rocky Mountains, made using independent downwind sampling at sites with 40 wells, were low. The average emission rates from these wells were less than half of the emissions that would be expected from just one high emission rate source per well that Howard (2015) argues should be prevalent at sites with high methane concentrations. Simply stated, if there were missing emissions of the magnitude asserted by Howard (2015), they would have significantly increased measured downwind concentrations."

However, this claim by (1) ignores the fact that the downwind tracer technique was used to measure  $CH_4$  emissions not from individual wells but from sites with an average of almost five wells per site, so the emission rates per site are much higher than the emission rates per well. In fact, the average emission rate per site measured by downwind tracer in the Rocky Mountain region was 0.66 scfm, over 50% greater than the expected BHFS sensor transition threshold of 0.4 scfm at a sample flow of 8 scfm. If the BHFS sample flow were reduced to 4 scfm due to low battery power or a tightly wrapped enclosure, then sensor transition failure could occur when measuring a source as small as 0.2 scfm. Consequently, a single measurement of a high emitter at these sites that was biased low by sensor failure could cause the observed underreporting of BHFS measurements compared to the tracer data.

To illustrate this, and because Dr. Allen and colleagues (1) found my comparison in (3) of their downwind tracer and on-site data (2) to be complex, I have tried to simplify that analysis here. Figure 1 presents the downwind tracer and on-site data from the UT study (2). For this analysis, I have removed only the two sites at which 98% or more of the reported on-site totals were comprised of estimated emissions, as opposed to actual BHFS measurements, since such a large fraction of estimated emissions would prevent a reasonable evaluation of the BHFS performance.

As seen in Figure 1, the downwind tracer data do in fact indicate that there are real regional differences in  $CH_4$  emissions from natural gas production, as (1) have asserted and as I have acknowledged in (3).

However, Figure 1 also shows clearly that the lower emissions in the Rocky Mountain region do not preclude the occurrence of BHFS sensor failure. When comparing the results on a site by site basis, the on-site totals (which as noted previously were a combination of BHFS measurements added to estimates of sources not measured) are substantially lower than the downwind tracer results for the Rocky Mountain and Mid-Continent sites where  $CH_4$  content was less than 82%, and substantially higher for sites in Appalachia where  $CH_4$  content was greater than 97% (sensor transition failure is much more likely at  $CH_4$  concentrations less than 97% (3)). Only one out of 13 sites with  $CH_4$  content < 82% (RM-5) had reported on-site emissions greater than the emissions measured by tracer, while all four sites with  $CH_4$  content > 97% had on-site emissions greater than those measured by tracer. The ratio of total on-site emissions to downwind tracer emissions for each region was as follows: Mid-Continent: 0.586; Rocky Mountain: 0.461; and Appalachia: 1.44.

Since the reported on-site emissions were greater than those measured by downwind tracer at all sites with well gas content of  $CH_4 > 97\%$  (the Appalachia region) where the BHFS likely functioned properly, I conclude that the estimation methods used by the UT study (2) actually overestimate emission rates as compared to actual whole-site emissions measured by downwind tracer analysis. Consequently, although this simplified comparison indicates that the on-site data are a factor of two too low at the Mid-Continent and Rocky Mountain sites, the actual effect of BHFS sensor failure is probably larger because the overestimates of emissions from the sources that were not measured somewhat obscures the underreporting by the BHFS, and I've discussed this in detail in (3). Therefore, although this direct comparison of the downwind tracer measurements to the on-site data for each site independently verifies the BHFS sensor failure, it does not reflect the full magnitude of the problem.

Given that the BHFS sensor failure can cause underreporting of natural gas emission rates which could create critical safety, health, and environmental problems, it is disappointing that (1) are willing to ignore the clear evidence – provided by their own downwind tracer measurements – of the effects of sensor failure in the UT BHFS (2) data set. The lead author of (1) and (2) served as the chair of the EPA Science Advisory Board during the period of research conducted by (2), and as such has a special obligation to disclose this issue since the BHFS is an EPA approved instrument. The BHFS is currently the standard instrument in the natural gas industry worldwide for measuring leak rates, and although upgrading firmware may reduce sensor failure, it does not eliminate it, and it is likely that most BHFS's in use have older firmware more susceptible to sensor failure. The presence of such a problem that can result in large leaks being reported as an order of magnitude or more lower than they actually are presents a frightening safety issue. It may have also caused many CH<sub>4</sub> emission inventories to be biased low, including those compiled by the USEPA Subpart W Greenhouse Gas Reporting program (9), the American Carbon Registry (10), and the United Nations Clean Development Mechanism (11).

For the last 12 years I have served as a professional firefighter, and in that role I have seen the tragic consequences that can occur when safety issues are ignored. Unfortunately, the misguided defense by such prominent researchers (1) of the UT BHFS data set (2) creates a distraction from the critical safety, health, and environmental problems that the BHFS sensor failure presents to the oil and NG industry. I call upon the authors and sponsors of the UT study (2) to meet their obligations to the safety of industry personnel and to the health of communities near oil and NG facilities by retracting the UT BHFS data set (2) so that this critically important problem can be recognized and addressed immediately.

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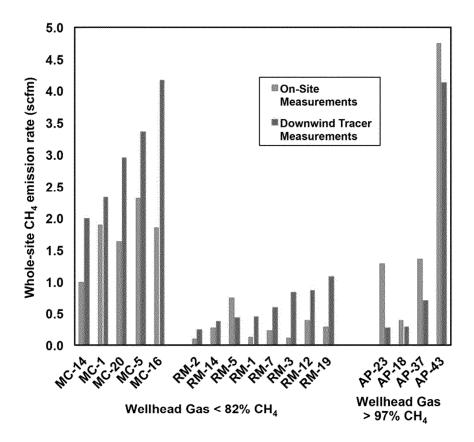
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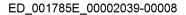
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#### **Figure Captions**

Figure 1. Comparison of downwind tracer measurements to reported on-site emission rates (compiled from BHFS measurements and estimates of sources not measured) in the UT study (2). Sites with lower CH4 wellhead gas content, where the BHFS is likely to experience sensor failure, have dramatically lower on-site emission rates compared to emission rates at the same sites measured by downwind tracer techniques. This comparison provides independent corroboration of the BHFS sensor failure, even in the Rocky Mountain region where tracer measurements indicate lower regional emission rates. BHFS = Bacharach Hi-Flow Sampler; MC = Mid-continent; RM = Rocky Mountain; AP = Appalachia.



70x66 M M (300 X 300 DPI)



To: Weitz, Melissa[Weitz.Melissa@epa.gov]; McKittrick, Alexis[McKittrick.Alexis@epa.gov]

From: Touche Howard

**Sent:** Wed 2/10/2016 3:37:50 AM

Subject: EPA Presentation Regarding Bacharach Sampler Sensor Failure

Melissa/Alexis --

Thanks for setting up the meeting last Friday regarding the issues with the Bacharach Hi-Flow Sampler. I just wanted to make a couple of observations.

I think the delays in starting the meeting could have been avoided if we had met ahead of the meeting, which is why I arrived 45 minutes before the scheduled start time. We had discussed me arriving early to get things set-up, so I was surprised to be turned away and told to come back ten minutes before the start time. As a result, by the time we got through security, it was time for the meeting to start.

My intent for being early was to be able to provide you a brief overview of what would be discussed and who I had invited to call in, as well as to get the presentation set up. Unfortunately, we didn't have time to do those things, resulting in delays because you had to find a press office person since a reporter had been invited and it also took the same amount of time to set up the computers.

Additionally, there were repeated problems with the computer as it stalled about a third of the way through, and then shut down completely about two thirds of the way through the presentation. Those events were significant distractions, both to me as a presenter as well as to the audience, since they could no longer see the presentation.

Ironically, I was cautioned prior to the meeting that sometimes problems are rigged into presentations when discussing topics that are uncomfortable for agencies. I don't think that's the case here, but you can see how the problems that occurred could feed into people's suspicions. However, I do think these problems were a result of this meeting not being a very high priority for you.

Well, that's understandable since you have a thousand things coming at you every day. But I think it would be very unfair to both of you if this slipped under your radar when it's such a critical issue, only to have it come back to haunt you later. Perhaps the first people at EPA to hear about the Volkswagen issues and the Flint water crisis were swamped as well and just didn't realize the importance of those problems until it was too late.

So I want to emphasize that the issues that I've raised really do have broad implications, and as such, they may get a lot of scrutiny. And in particular, given all that's led up to where we are now, how EPA handles these issues may in particular get a lots of attention.

Also, I have a follow-up question for Alexis based on our conversation at the EPA conference in Pittsburgh. When I initially raised some of these issues to you then, your reply was that I should be cautious because people might go after my work. That's a pretty unusual response from an EPA person, so I assume that someone discussed these issues with you before I did and

specifically told you that they would retaliate. If that's the case, I would like to know who that was, because that's an unacceptable response to these problems.

It's very important that you understand that the environmental, health, and -- especially -- safety issues far outweigh any concerns I might have about being retaliated against. Certainly we hope the occurrence of an explosion or fire is a remote possibility due to Hi-Flow sensor failure, but there's no excuse for exposing people to any risk of a preventable tragedy,

I'll acknowledge that my concerns are probably heightened by the last twelve years I've spent as a professional firefighter. I'm lucky, in the sense that I've spent my entire career at our busiest station, but that also means I've seen a lot of bad things happen to people. Dragging a body out of a fire and feeling their burnt flesh come off on your turnout gear is a terrible experience. But what's worse -- far worse -- is hearing the screams of agony when someone has been badly burned but survived.

Honestly, I wouldn't think it would take those type of experiences for anyone to realize the importance of disclosing the sensor failure issue as rapidly as possible. Unfortunately, however, here we are, over two years later, and almost no progress on this problem has been made.

You two might be the last chance for this to be address	ssed.
Regards,	
Touche'	

**To:** Weitz, Melissa[Weitz.Melissa@epa.gov]; McKittrick, Alexis[McKittrick.Alexis@epa.gov]; Daniel Zimmerle[Dan.Zimmerle@colostate.edu]

From: Touche Howard

**Sent:** Tue 2/9/2016 11:52:58 PM

Subject: EDF Compressor Station Methane Study

Melissa/Alexis --

One additional implication of the Bacharach Hi-Flow sensor failure is that you should exclude data from any other sources that used the Bacharach sampler unless it can be certified to have been collected with a sampler using software Version 3.03 or higher. For instance, the EDF compressor station work made a lot of measurements using the Bacharach Hi-Flow. I've discussed this with Dr. Zimmerle, and originally hoped that he'd be able to get approval for us to look closely at the data to see if we could determine signs of sensor failure. However, it doesn't appear he'll be able to get approval for that any time soon, so unfortunately the alternative is to just exclude all data not collected with the newer software.

I did look at the tracer measurements they made to compare to on-site measurements, but I narrowed those down to a subset of 18 sites that were measured using only reliable methods (no acoustics, for instance), had little or no engine exhaust emissions, and were in the same mode for both measurement techniques. For these sites, the tracer and on-site measurements should agree quite well, but they actually only agree within a factor of two for half of those cases, so that level of uncertainty prevents using the tracer data to rule out Hi-Flow sensor failure.

As I mentioned at the meeting, I think we're too quick -- not anybody in particular, but all of us -- to try to reconcile quality assurance results as opposed to trying to understand them. I think that the disparity in the tracer vs on-site results in the compressor station work provides an opportunity to understand where things might go wrong and provide guidance to improve future programs. But unfortunately for now, the Hi-Flow data collected with older software should be excluded.

Hopefully that will be easy information for Dr. Zimmerle to release to you since it doesn't require any site or company identification -- it's only identifying the software version for each site.

I've included Dr. Zimmerle on this thread in case he has any comments and would be happy to discuss this with all of you if that's helpful.

Thanks,

Touche'

To: allen@che.utexas.edu[allen@che.utexas.edu] Cc: McKittrick, Alexis[McKittrick.Alexis@epa.gov]; terri shires@aecom.com[terri shires@aecom.com]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Gunning, Paul[Gunning.Paul@epa.gov]; McCabe, Janet[McCabe.Janet@epa.gov]; RAlvarez@edf.org[RAlvarez@edf.org]; shamburg@edf.org[shamburg@edf.org]; Fernandez, Roger[Fernandez.Roger@epa.gov]; rharriss@edf.org[rharriss@edf.org]; ritterk@api.org[ritterk@api.org]; dnelson@edf.org[dnelson@edf.org]; sedlak-office@est.acs.org[sedlak-office@est.acs.org]; dmccabe@catf.us[dmccabe@catf.us]; dlyon@edf.org[dlyon@edf.org]; Maxwell, Dave (Austin)[dave.maxwell@aecom.com]; dschroeder@catf.us[dschroeder@catf.us]; dzavala@edf.org[dzavala@edf.org]; Chuck Kolb[kolb@aerodyne.com]; Gamas, Julia[Gamas.Julia@epa.gov]; linda.lee@arb.ca.gov[linda.lee@arb.ca.gov]; bmordick@nrdc.org[bmordick@nrdc.org]; amrowka@arb.ca.gov[amrowka@arb.ca.gov]; casey.pickering@erg.com[casey.pickering@erg.com]; Wisetiawa@arb.ca.gov[Wisetiawa@arb.ca.gov]; Smith, James-D[Smith.James-D@epa.gov]; Snyder, Jennifer[Snyder.Jennifer@epa.gov]; michael.ege@tceq.texas.gov[michael.ege@tceq.texas.gov]; paige.sprague@tceg.texas.gov[paige.sprague@tceg.texas.gov]; adam.pacsi@chevron.com[adam.pacsi@chevron.com]; Rees, Jeff[Jeff.Rees@pxd.com]; matt.harrison@aecom.com[matt.harrison@aecom.com]; alr@andrew.cmu.edu[alr@andrew.cmu.edu]; awilcox@harcresearch.org[awilcox@harcresearch.org]; andres.restrepo@sierraclub.org[andres.restrepo@sierraclub.org]; gabrielle.petron@noaa.gov[gabrielle.petron@noaa.gov]; natalie.spiegel@sierraclub.org[natalie.spiegel@sierraclub.org]; nathan.matthews@sierraclub.org[nathan.matthews@sierraclub.org]; rsawyer@me.berkeley.edu[rsawyer@me.berkeley.edu]; Ganapathy, Roopa (EC/EC)[Roopa.Ganapathy@canada.ca]; vgowrishankar@nrdc.org[vgowrishankar@nrdc.org]; dan.hill@pe.tamu.edu[dan.hill@pe.tamu.edu]; Matthew.Fraser@asu.edu[Matthew.Fraser@asu.edu]; seinfeld@caltech.edu[seinfeld@caltech.edu]

From: Touche Howard

**Sent:** Tue 12/15/2015 5:47:46 PM

Subject: Re: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

#### Dave --

Just to follow up on the safety issue, I did a news media search to see what the current state of natural gas industry safety is, because if fires and explosions have been eliminated over time, then my fears would be groundless. But, it turned out to be much worse than I expected. It looks like there have been at least 33 explosions or fires at natural gas facilities over the past five years, killing 11 people and injuring 126 others. You can't tell the cause of all these incidents from the media reports, but it's clear that it's still true that natural gas facilities can and do blow up.

So the issue of safety is still very relevant. But even if it weren't, I'm sure you and Matt would want to address this issue immediately, just for the health and environmental aspects. If nothing else, I believe companies can start their 2016 Subpart W reporting measurements in January, and since two reporting years have gone by since this problem came to light, I think we can all agree that we don't want to let another year go by that could be affected by Hi-Flow sensor failure.

Thanks,

Touche'

On Mon, Dec 14, 2015 at 4:42 PM, Touche Howard <a href="mailto:touche.howard@indacoags.com">touche.howard@indacoags.com</a>> wrote:

Dave --

I think that Matt's statement of "I see no safety issue" (regarding the Bacharach Hi-Flow sampler's problem of reporting leaks as far smaler than they actually are) might have resulted from your team either not being aware of all the potential uses of the Hi-Flow sampler or from having a somewhat narrow view of what problems can compromise safety.

Probably half of the leak measurement programs I've conducted were for private companies whose primary goals were to reduce gas loss and to improve safety, as opposed to cataloging greenhouse gas emissions. At 1 to 2% of all the facilities I've been to, we found leaks that caused the operators to immediately shut down equipment. Examples include leakage into compressor distance pieces that was large enough to cause back pressure into the engine crankcase, flanges that had a leak rate large enough that it might cause further gasket erosion and failure, and large leaks at welds on compressor fuel gas systems that might catastrophically fail or be large enough to reach an ignition source due to induced sparking at vibrating components in the ignition coil area.

Did we prevent explosions in those cases? We'll never know, but we did provide one layer of defense by eliminating imminently dangerous conditions. So if only 1% of facilities have a dangerous underlying condition that might go undiscovered if a Hi-Flow sampler fails, is it really worth an hour of your time to address this issue? I think most people would say yes.

Even high flow surveys that focus on research or greenhouse gas reporting have the opportunity to reduce dangerous conditions if done properly. I think the protocol in most (hopefully all) leak measurement programs, whatever their focus, is to immediately alert facility operators of any hazardous conditions found. So it's certainly not acceptable to leave hazards unidentified due to sampler failure just because many surveys are focused on greenhouse gas emissions instead of facility integrity.

Other instances where sampler failure might affect safety are when it is used to make an on the spot repair decision when a leak is discovered by an operator and when it is used to survey facilities being put into initial service. And as I pointed out previously, we don't know all the ways a sampler might be used now or in the future. If, for instance, it were used to rank distribution leaks for repair, under reporting large leaks could have tragic consequences.

Now you might think that other indications, such as an IR camera, or auditory, visual, and olfactory (AVO) detection would provide clues that a leak was much larger than the sampler indicated, but most people just don't have that level of experience, and a noisy and/or hot environment can make it even more difficult. There's an excellent example of this in your Phase II pneumatic work, where Device No. XQ01-PC04 was measured both by

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Hi-Flow (0.13 scfh) and meter (37.37 scfh), and you assume the Hi-Flow measurement is too low due to the device not being adequately enclosed. However, this device was a continuous bleed controller with a high emission rate (in the top 20% of the continuous controllers you measured). Consequently, even though the Hi-Flow was making an easy to read steady state measurement for most of that interval, your technicians did not recognize that the Hi-Flow reading was almost 300 times too low (if they had, they would have certainly attempted to correct the problem while the measurement was being made). This highlights that even people who had been making these type of measurements day after day during an extensive field program could not accurately judge emission rates without reliable instrumentation.

And although safety systems like gas detectors or hot work permits provide one line of defense, they can't always protect the facility from a leak that could have been fixed but wasn't, and then either failed catastrophically or found an ignition source before automatic detection shut down equipment. Having been to so many facilities, I've heard lots of stories of past explosions. My favorite was was told to me by an operator who was the son of a compressor station manager. When he was growing up, they lived near the station, and one night after dinner he wanted to go to the mechanic's shop at the site to work on his car. Oh, no, his mother says, it's your turn to do the dishes. So there he is, sulking at the sink, when the station blows up, basically right in front of him as he's watching out the kitchen window, and destroying with it the mechanic's shop where he would have been if his mother hadn't made him wash dishes.

Unfortunately, not all the stories had a happy ending like that.

I hope this provides a better perspective on the safety issues involved.

Thanks,

Touche'

On Wed, Dec 9, 2015 at 8:56 PM, Harrison, Matt < matt.harrison@aecom.com > wrote:

I see no safety issue. HiFlows are never used as safety devices to my knowledge

Matt Harrison 512-694-0572 Sent from my iPhone

On Dec 9, 2015, at 2:25 PM, "Touche Howard" < touche.howard@indacoaqs.com > wrote:

#### Dave --

Now that the EPA is considering using your initial EDF study at production sites (published in PNAS in 2013) and your follow-up study on pneumatic controllers (published in ES&T in 2014), it's critical that we resolve the Hi-Flow sensor failure and other quality assurance issues surrounding those studies as soon as possible. The quickest way to do that is for us to directly discuss these issues with EPA, and I think once you understand the evidence, you'll be able to see the problems immediately. To that end, let's try to get together tomorrow or Friday. (Melissa and Alexis - I can come up and meet with you either day, and if Dave can't make it, he can call in.)

My biggest concern is safety -- having an instrument that reports natural gas leaks far lower than they actually are is clearly a huge safety issue, and as long as you tell people that this problem didn't occur in your work, it will be very hard for anyone to take it seriously. Meanwhile, for you and EPA, this also represents important health and environmental concerns. And of course since you were chair of the EPA Science Advisory Board while you were conducting this research, and the Hi-Flow sampler is one of the methods approved by EPA to make measurements for their greenhouse gas reporting program under Subpart W, I'm sure you feel a special responsibility to address these issues as soon as possible.

I've attached my ESE paper outlining the problems in your initial 2013 production study as well as my letter and your response about the 2014 study. I've also attached a reply that I wrote in response to your commentary on my paper in ESE, because even though you withdrew that commentary after seeing my response, I think my response did clarify some of the issues.

Since we unfortunately haven't had an opportunity to discuss these issues directly, I'll summarize the evidence here and what I believe are your counterpoints, based on your reviews of my paper and the commentary you submitted. I also want to allay your concerns, which you've stated to others, that I'm raising these issues because I want to sell my own samplers or services. I'm only wrapping up loose ends now, and after this I won't be working in this area any more.

The first issue is sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS), where it can fail to transition from the low range (0 to 5% gas) catalytic oxidation sensor to the high range (5 to 100% gas) thermal conductivity detector, which can cause the sampler to report large leaks as being much smaller that they are. We don't know why this happens, but there's no question that it can, because we demonstrated it in three different instruments, including yours. It doesn't seem to occur for pure methane streams, but we've seen it in the field for gas streams with methane content as high as 91% (J. Air Waste Manag. Assoc. 65:856–862. doi: 10.1080/10962247.2015.1025925).

The effect of this problem is clear in your Phase I data, which I've plotted below showing emission rate as a function of site methane composition. As you can see, most of the high emitters only show up at sites with high methane compositions, and there's no reason that should happen in the real world, especially when you consider that it occurs for several different types of sources.

<image.png>G

Now I believe your counter argument is that this phenomenon is due to air pollution control regulations reducing emissions in the Rocky Mountain region, where the methane content of the gas is lower as well. However, several things tell us that's not the cause of the trend in the figure above. First, even when you take the Rocky Mountain region out of the analysis, there's still far more high emitters at sites with higher methane content. Second, even within just the Appalachia region, the occurrence of high emitters increases dramatically over a very narrow range of site methane compositions, from 95% to 98% methane (shown below). What that tells us is that sampler can start seeing some of the high emitters once methane composition is in the range of 95%, but is still missing a lot of them until methane composition gets up to the 97 to 98% range. This is also an extremely important indicator that this problem could be occurring even for gas streams with methane content above 95%, meaning the problem could occur in all segments of the natural gas industry.

<image.png>

Finally, your emissions measurements made by tracer technique confirm that sensor failure occurred and that the trend of emission rate vs concentration is not caused by regional differences. Now, in your comment you said you found my analysis of your tracer data complex, probably because I showed how Hi-Flow measurements got lower and lower than the tracer measurements for sites with fewer estimated emissions from sources like tanks. So I've simplified that analysis, and just removed the two sites that had 98% or more of the emissions estimated as opposed to measured. This comparison of the tracer versus on site Hi-Flow measurements is shown below.

#### <image.png>

So clearly, as you've suggested, there are regional differences, assuming these sites are representative. The tracer data shows that the emissions from sites in the Rocky Mountain (RM) region are lower than the sites in the Mid-continent (MC) region, although in the same range as 75% of the Appalachia (AP) sites. But just as clearly, the sites with lower methane content (Rocky Mountain and Mid-continent, where sensor failure might occur consistently) have far lower (about a

factor of two) Hi-Flow measurements than the tracer technique. Meanwhile, the sites with high methane content (Appalachia, where the problem isn't expected to occur) have Hi-Flow measurements close to or exceeding the tracer measurements. Keep in mind that because some of the on-site data comes from estimates, this masks the magnitude of the error, but at least this is a simple comparison.

Now if the variations between the tracer and the Hi-Flow were due to random experimental errors, then we'd expect roughly 50% of the sites to have tracer greater than Hi-Flow, and 50% lower. It's actually a 70/30 split, but the remarkable thing is that we can predict which region will have tracer greater than Hi-Flow and which won't. This is pretty much the same thing as me being able to walk into a bar and betting the barmaid that if I stand on her side of the bar and flip a coin it will always come up heads, but if I stand on my side of the bar and flip a coin, it will always come up tails. And in between drinks, we run that experiment, and it turns out that I'm right 16 out of 17 times.

Now that's a bar bet I'd like to be able to make routinely.

You also said in your unpublished comment to ESE that the testing I conducted on your instrument and others in March of 2013 showed a low occurrence of this problem. That's true of course, but I was surprised you said that, since you know that immediately after we did that testing that I met with some very experienced Hi-Flow technicians who specifically told me that they had fixed some of their samplers that had been reporting leaks too low by upgrading the sampler's software. Since all of the samplers we tested when we tested yours had new generation software, the only real surprise is that we saw any failure at all, and that failure was in your sampler. So even though new software improves the problem, it doesn't fix it completely. Additionally, there are lots of these samplers around the US and the world using older software, and lots of data that has been collected using samplers prior to software upgrades.

One other argument you made was that your Phase I pneumatic data, made by Hi-Flow, was higher than your Phase II pneumatic data, collected by meter, and if your Hi-Flow had been reporting too low, this should have been the other way around. The reason this isn't true is that your Phase I pneumatic data is clearly an emitter data set (95% of them are emitting) while your Phase II data set is a comprehensive data set (about 21% are actual emitters). So you accidentally excluded sampling zero emitters in Phase I, which biases that data high by a factor of four to five, and offsets any Hi-Flow sensor failure. Additionally, the Phase II data actually shows exactly what I predicted to you it would show -- that the high emitters are more predominant at sites with lower methane compositions when measured by the inline meter as opposed to your Phase I measurements, where the sensor failure caused the high emitters at those sites to be under reported.

In any case, I think this shows that it probably would have been better to involve me directly in discussions you had with the EDF committees and others about this problem after I brought it to you in October of 2013, because I could have explained immediately why the reasons you thought this problem didn't affect your Phase I data were incorrect. It has been puzzling to me that given the overwhelming evidence, that this problem wasn't obvious to you, but I'm wondering if that might be due to inexperience with field measurements. As an example, in both your Phase I and Phase II papers, you incorrectly describe the operation of the Hi-Flow sensors, and without understanding that the Hi-Flow has to to switch back and forth between sensors to make accurate measurements, it's probably impossible for you to understand the sensor transition problem.

I'm wondering if inexperience might have also led to the problems in your Phase II work as well. It's a harsh environment for meters to be transported between field sites on rough roads and have raw natural gas run through them, and I think most people with experience in field measurements would have built in a routine testing of those meters during the project, rather than just check them before and after the project as you did. When you're out in the field looking at pneumatics, you see lots of them with oil or other hydrocarbon accumulations, so it's easy to picture how the meter sensor could get fouled, as yours did. I would think at least a weekly multi-point meter calibration and a daily single point flow check would be required to ensure accurate measurements, which is what was done during the EDF WSU distribution work. The Indaco Hi-Flows that were used in that project have a very similar flow measurement system to your Fox meter, which is a thermal element in a tube, and even though the distribution study was a much less harsh environment, where leaks of relatively clean distribution gas were measured and the flow system dilutes those leaks with air before the gas hits the sensors, full scale weekly calibrations and single point daily flow checks were conducted.

Now, as you remember, while that project was ongoing, I found that one of your two primary meters was measuring too low by a factor of three. Well, that's not a surprise, given the harsh environment. I haven't used the particular meter that you were using before, but I did look at the manual for it, and it clearly states that a dirty sensor will cause measurements to be too low.

But I think how you addressed that issue indicates further inexperience. Since you don't mention the meter test I made showing it was a factor of three too low in your paper, but only indicate that you found the problem post project, it appears that you just kept using the meter, without trying to figure out what was wrong with it, and without instituting any additional meter checks.

Instead, it wasn't until the end of the project that you did any further checks, and at that point the response of the meter had changed again, to being low by about 34%. In order to understand more about the problem, you tried to use your Hi-Flow data to validate the meter results. Now your laboratory comparisons of the two for the most part are excellent and agree within 10%. But surprisingly, your

field comparisons of the Hi-Flow to the meters are far worse. For measurements where either one or the other was >0.5 scfh, only 4 out of 19 (21%) are within 25%, and even for measurements >6 scfh, only 3 out of 10 (30%) are within 25% of each other. You do allude to the possibility of leaks affecting the measurements but don't give any indication that you tried to quantify the leaks that you think affected the measurements.

For comparison, in the WSU distribution work, where direct and tracer measurements were compared, 10 out of 14 (71%) were within 50% of each other, over a range of about 0.6 to 56 scfh. Now I would have liked that to be better, but I think I understand some of the challenges, one being that some of those that are far off are at really low emission rates, so missing just one source could throw you off a lot. But keep in mind, that's measuring the whole M&R facility or an underground leak, and comparing it to a downwind tracer flux measurement, so you have lots of challenges including multiple measurements at the facility and tracer source configurations.

But for your pneumatic work, while doing a direct comparison of Hi-Flow to meters, for just single sources, only 7 of 19 (37%) were within 50% of each other over a similar emission range of 0.5 to 60 scfh.

So unfortunately your comparison of High Flow to meters should not have been used to justify correcting your meter, especially when my direct test of that meter's performance mid-project showed it was much worse than the post project check indicated.

Another indication of the meter uncertainty came from Matt Harrison, who was present when I found that your meter was reading a factor of three too low, and said at the time, "Yeah, everyone knows that meter is flaky. You can hook it up to an pneumatic and hear the pneumatic fire but not see anything on the meter."

Now, along with the sensor getting dirty, your meter measurements might have been affected by two other factors mentioned in the meter manual. These meters are supposed to be oriented upright, and you need a certain length of straight run (I think for the meter you were using, six inches) before the meter. However, it appears, looking at a slide from the presentation about the project on your website shown below, that those conditions weren't met either. Although you can see in the close up that the meter is marked with a label that says "Keep Upright and Level", that condition hasn't been met in either configuration pictured. Additionally, the entrance length doesn't appear to meet the required distance either.

<Upside Down Meter 1.jpg>

<Upside Down Meter Close-up.jpg>

I think these issues were all compounded by perhaps your lack of experience with what information editors and reviewers need to evaluate field measurement papers. Your meter problem is only mentioned in a footnote on page 59 of your Supplementary Information, and was likely missed by the editor and reviewers. But if reviewers with substantial field experience understood the entire picture -- that you only checked your calibration before and after the project, that there was an undisclosed mid project test showing meter performance was much worse than the correction you applied, that after you were shown one meter was faulty in the middle of the project that you simply continued to use it without finding out what was wrong or instituting improved calibration checks, "that everyone knew that meter was flaky," and that your Hi-Flow and meter field measurements don't compare very well -- I believe they would conclude that you didn't meet the fundamentals of quality assurance and that the paper would have been rejected.

So unfortunately neither the Phase I or Phase II data should be used by EPA. Although there may be large uncertainties in inventories, we shouldn't include numbers that have such large question marks. Think about cancer treatments. Those have very uncertain outcomes, but that doesn't mean that we don't want good quality assurance in cancer research or in the dosages of drugs or radiation therapy that are used. And when you consider the broad environmental impact of air toxics to the communities surrounding oil and gas facilities as well as the consequences of climate change, it's critical that we use the best data possible.

And as I said at the start, safety is my biggest concern regarding the HiFlow sensor failure, and I think perhaps again inexperience has caused you not to fully appreciate what a critical safety issue this is. I've spent a lot of time measuring leak rates at natural gas facilities, and I've seen facility personnel shut down units in order to address large leaks that we found due to safety concerns -- I've done lots of leak measurement programs that were focused more on the integrity of the facility rather than the issue of greenhouse gases. Additionally, we don't know how the sampler might be used in the future -- for instance, given GTI's and WSU's work in distribution, it might be used to rank leaks for repair in that segment (even though the WSU study used a different version of the sampler not affected by this problem).

James Reason wrote a really great book about the Swiss cheese theory of disasters (Reason, James (1997). Managing the risks of organizational accidents.

Aldershot: Ashgate. ISBN 1840141042.) which is widely studied in aviation, engineering, and the fire service. In it he describes how the really terrible things that happen usually occur because there have been failures on several levels, and those failures line up to let something really bad happen.

We had a terrible example of that happen here in North Carolina a couple of years

ago. A couple checked into a hotel, and the next morning they were dead. Seven weeks later, an 11 year old boy died in the same room, and although his mother survived, she had permanent brain damage.

All of that could have been avoided, because they were killed by carbon monoxide. You might have seen this on 20/20:

http://abcnews.go.com/US/north-carolina-best-western-room-225-open-deaths/story?id=21564280

Here's how it all lined up:

- 1) The hotel pulled an old pool heater out of another property and installed it at that hotel, even though it was at the end of its life, meaning it was inefficient and was at risk for producing more carbon monoxide, and they didn't get a city inspection permit;
- 2) The vent pipe was corroded, and let the CO escape under the room where everyone was killed;
- 3) There were holes in the fire place in the room that let more CO in that would have come in otherwise;
- 4) The CO detectors that were supposed to have been installed in the rooms were actually natural gas detectors, installed by mistake.

So that's what killed the first couple.

But here's why the little boy died:

- 1) Three days after the couple was killed, a family in the room above got really sick, and complained, but the hotel didn't pay attention;
- 2) The family of the first couple raised warnings with the hotel and police that it might be CO and again no one paid attention;
- 3) The medical examiner didn't visit the scene of the first couple and see that the wife had thrown up (an important clue in CO poisoning)
- 4) He also didn't put an expedite order on their blood work, so it sat for 40 days (two people simultaneously dead in an enclosed space -- a huge alarm bell for some toxic substance, especially CO);

- 5) He finally got the results four days before the child died in the room, but;
- 6) He sat on them for a week and by the time he finally sent them out to the local police; the child was had been killed and his mother permanently injured.

That's a tragic story, all right. And as you can imagine, the two families are suing everyone in sight that had anything to do with any of that, and I would too if I had lost a family member. Meanwhile, the DA also charged the head of the hotel management group with three counts of manslaughter, and all of those cases are still on going.

That's just one example of how tragic things can happen when we don't do everything possible to ensure people's safety. But if you do just a little bit of research, you'll see how frighteningly common that is.

So I know you'll want to address the Hi-Flow sensor failure issue immediately.

As I suggested at the start, let's do it this week. I can go up and meet with EPA tomorrow or Friday, and if you can't be there in person, you can call in, and you can have any interested parties from EDF or your production committees call in as well. i know everyone's busy, but this won't take more than an hour, and I think we should all be willing to make that much time for such a critical issue.

Just let me know when the best time for all of you is.

Thanks,

Touche'

<Howard Energy Science and Engineering Analysis of UT Data Set 2015.pdf>

<ES&T Comment on Allen et al. Methane Emissions from Process Equipment.pdf>

<Dave Allen Response to ES&T Letter.pdf>

<Touche Response to Dave Allen Comment in ESE Submitted 09 10 2015.pdf>

To: McKittrick, Alexis[McKittrick.Alexis@epa.gov]; DeFigueiredo,

Mark[DeFigueiredo.Mark@epa.gov]; Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Friedman,

Kristina[Friedman.Kristina@epa.gov]

From: Weitz, Melissa

**Sent:** Mon 12/14/2015 9:49:42 PM

Subject: FW: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

FYI

From: Touche Howard [mailto:touche.howard@indacoags.com]

Sent: Monday, December 14, 2015 4:42 PM

To: allen@che.utexas.edu

Cc: McKittrick, Alexis <McKittrick.Alexis@epa.gov>; terri shires@aecom.com; Weitz, Melissa <Weitz.Melissa@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; McCabe, Janet <McCabe.Janet@epa.gov>; RAlvarez@edf.org; shamburg@edf.org; Fernandez, Roger <Fernandez.Roger@epa.gov>; rharriss@edf.org; ritterk@api.org; dnelson@edf.org; sedlakoffice@est.acs.org; dmccabe@catf.us; dlyon@edf.org; Maxwell, Dave (Austin) <dave.maxwell@aecom.com>; dschroeder@catf.us; dzavala@edf.org; Chuck Kolb <kolb@aerodyne.com>; Gamas, Julia <Gamas.Julia@epa.gov>; linda.lee@arb.ca.gov; bmordick@nrdc.org; amrowka@arb.ca.gov; casey.pickering@erg.com; Wisetiawa@arb.ca.gov; Smith, James-D <Smith.James-D@epa.gov>; Snyder, Jennifer <Snyder.Jennifer@epa.gov>; michael.ege@tceq.texas.gov; paige.sprague@tceq.texas.gov; adam.pacsi@chevron.com; Jeff.Rees@pxd.com; matt.harrison@aecom.com; alr@andrew.cmu.edu; awilcox@harcresearch.org; andres.restrepo@sierraclub.org; gabrielle.petron@noaa.gov; natalie.spiegel@sierraclub.org; nathan.matthews@sierraclub.org; rsawyer@me.berkeley.edu; Ganapathy, Roopa (EC/EC) < Roopa.Ganapathy@canada.ca>; vgowrishankar@nrdc.org; dan.hill@pe.tamu.edu; Matthew.Fraser@asu.edu; seinfeld@caltech.edu Subject: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

Dave --

I think that Matt's statement of "I see no safety issue" (regarding the Bacharach Hi-Flow sampler's problem of reporting leaks as far smaler than they actually are) might have resulted from your team either not being aware of all the potential uses of the Hi-Flow sampler or from having a somewhat narrow view of what problems can compromise safety.

Probably half of the leak measurement programs I've conducted were for private companies whose primary goals were to reduce gas loss and to improve safety, as opposed to cataloging greenhouse gas emissions. At 1 to 2% of all the facilities I've been to, we found leaks that caused the operators to immediately shut down equipment. Examples include leakage into compressor distance pieces that was large enough to cause back pressure into the engine crankcase, flanges that had a leak rate large enough that it might cause further gasket erosion and

failure, and large leaks at welds on compressor fuel gas systems that might catastrophically fail or be large enough to reach an ignition source due to induced sparking at vibrating components in the ignition coil area.

Did we prevent explosions in those cases? We'll never know, but we did provide one layer of defense by eliminating imminently dangerous conditions. So if only 1% of facilities have a dangerous underlying condition that might go undiscovered if a Hi-Flow sampler fails, is it really worth an hour of your time to address this issue? I think most people would say yes.

Even high flow surveys that focus on research or greenhouse gas reporting have the opportunity to reduce dangerous conditions if done properly. I think the protocol in most (hopefully all) leak measurement programs, whatever their focus, is to immediately alert facility operators of any hazardous conditions found. So it's certainly not acceptable to leave hazards unidentified due to sampler failure just because many surveys are focused on greenhouse gas emissions instead of facility integrity.

Other instances where sampler failure might affect safety are when it is used to make an on the spot repair decision when a leak is discovered by an operator and when it is used to survey facilities being put into initial service. And as I pointed out previously, we don't know all the ways a sampler might be used now or in the future. If, for instance, it were used to rank distribution leaks for repair, under reporting large leaks could have tragic consequences.

Now you might think that other indications, such as an IR camera, or auditory, visual, and olfactory (AVO) detection would provide clues that a leak was much larger than the sampler indicated, but most people just don't have that level of experience, and a noisy and/or hot environment can make it even more difficult. There's an excellent example of this in your Phase II pneumatic work, where Device No. XQ01-PC04 was measured both by Hi-Flow (0.13 scfh) and meter (37.37 scfh), and you assume the Hi-Flow measurement is too low due to the device not being adequately enclosed. However, this device was a continuous bleed controller with a high emission rate (in the top 20% of the continuous controllers you measured). Consequently, even though the Hi-Flow was making an easy to read steady state measurement for most of that interval, your technicians did not recognize that the Hi-Flow reading was almost 300 times too low (if they had, they would have certainly attempted to correct the problem while the measurement was being made). This highlights that even people who had been making these type of measurements day after day during an extensive field program could not accurately judge emission rates without reliable instrumentation.

And although safety systems like gas detectors or hot work permits provide one line of defense, they can't always protect the facility from a leak that could have been fixed but wasn't, and then either failed catastrophically or found an ignition source before automatic detection shut down equipment. Having been to so many facilities, I've heard lots of stories of past explosions. My favorite was was told to me by an operator who was the son of a compressor station manager. When he was growing up, they lived near the station, and one night after dinner he wanted to go to the mechanic's shop at the site to work on his car. Oh, no, his mother says, it's your turn to do

the dishes. So there he is, sulking at the sink, when the station blows up, basically right in front of him as he's watching out the kitchen window, and destroying with it the mechanic's shop where he would have been if his mother hadn't made him wash dishes.

Unfortunately, not all the stories had a happy ending like that.

I hope this provides a better perspective on the safety issues involved.

Thanks,

Touche'

On Wed, Dec 9, 2015 at 8:56 PM, Harrison, Matt <matt.harrison@aecom.com> wrote:

I see no safety issue. HiFlows are never used as safety devices to my knowledge

Matt Harrison

512-694-0572

Sent from my iPhone

On Dec 9, 2015, at 2:25 PM, "Touche Howard" <touche.howard@indacoaqs.com> wrote:

Dave --

Now that the EPA is considering using your initial EDF study at production sites (published in PNAS in 2013) and your follow-up study on pneumatic controllers (published in ES&T in 2014), it's critical that we resolve the Hi-Flow sensor failure and other quality assurance issues surrounding those studies as soon as possible. The quickest way to do that is for us to directly discuss these issues with EPA, and I think once you understand the evidence, you'll be able to see the problems immediately. To that end, let's try to get together tomorrow or Friday. (Melissa and Alexis - I can come up and meet with you either day, and if Dave can't make it, he can call in.)

My biggest concern is safety -- having an instrument that reports natural gas leaks far lower than they actually are is clearly a huge safety issue, and as long as you tell people that this problem didn't occur in your work, it will be very hard for anyone to

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take it seriously. Meanwhile, for you and EPA, this also represents important health and environmental concerns. And of course since you were chair of the EPA Science Advisory Board while you were conducting this research, and the Hi-Flow sampler is one of the methods approved by EPA to make measurements for their greenhouse gas reporting program under Subpart W, I'm sure you feel a special responsibility to address these issues as soon as possible.

I've attached my ESE paper outlining the problems in your initial 2013 production study as well as my letter and your response about the 2014 study. I've also attached a reply that I wrote in response to your commentary on my paper in ESE, because even though you withdrew that commentary after seeing my response, I think my response did clarify some of the issues.

Since we unfortunately haven't had an opportunity to discuss these issues directly, I'll summarize the evidence here and what I believe are your counterpoints, based on your reviews of my paper and the commentary you submitted. I also want to allay your concerns, which you've stated to others, that I'm raising these issues because I want to sell my own samplers or services. I'm only wrapping up loose ends now, and after this I won't be working in this area any more.

The first issue is sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS), where it can fail to transition from the low range (0 to 5% gas) catalytic oxidation sensor to the high range (5 to 100% gas) thermal conductivity detector, which can cause the sampler to report large leaks as being much smaller that they are. We don't know why this happens, but there's no question that it can, because we demonstrated it in three different instruments, including yours. It doesn't seem to occur for pure methane streams, but we've seen it in the field for gas streams with methane content as high as 91% (J. Air Waste Manag. Assoc. 65:856–862. doi: 10.1080/10962247.2015.1025925).

The effect of this problem is clear in your Phase I data, which I've plotted below showing emission rate as a function of site methane composition. As you can see, most of the high emitters only show up at sites with high methane compositions, and there's no reason that should happen in the real world, especially when you consider that it occurs for several different types of sources.

<image.png>G

Now I believe your counter argument is that this phenomenon is due to air pollution

control regulations reducing emissions in the Rocky Mountain region, where the methane content of the gas is lower as well. However, several things tell us that's not the cause of the trend in the figure above. First, even when you take the Rocky Mountain region out of the analysis, there's still far more high emitters at sites with higher methane content. Second, even within just the Appalachia region, the occurrence of high emitters increases dramatically over a very narrow range of site methane compositions, from 95% to 98% methane (shown below). What that tells us is that sampler can start seeing some of the high emitters once methane composition is in the range of 95%, but is still missing a lot of them until methane composition gets up to the 97 to 98% range. This is also an extremely important indicator that this problem could be occurring even for gas streams with methane content above 95%, meaning the problem could occur in all segments of the natural gas industry.

### <image.png>

Finally, your emissions measurements made by tracer technique confirm that sensor failure occurred and that the trend of emission rate vs concentration is not caused by regional differences. Now, in your comment you said you found my analysis of your tracer data complex, probably because I showed how Hi-Flow measurements got lower and lower than the tracer measurements for sites with fewer estimated emissions from sources like tanks. So I've simplified that analysis, and just removed the two sites that had 98% or more of the emissions estimated as opposed to measured. This comparison of the tracer versus on site Hi-Flow measurements is shown below.

#### <image.png>

So clearly, as you've suggested, there are regional differences, assuming these sites are representative. The tracer data shows that the emissions from sites in the Rocky Mountain (RM) region are lower than the sites in the Mid-continent (MC) region, although in the same range as 75% of the Appalachia (AP) sites. But just as clearly, the sites with lower methane content (Rocky Mountain and Mid-continent, where sensor failure might occur consistently) have far lower (about a factor of two) Hi-Flow measurements than the tracer technique. Meanwhile, the sites with high methane content (Appalachia, where the problem isn't expected to occur) have Hi-Flow measurements close to or exceeding the tracer measurements. Keep in mind that because some of the on-site data comes from estimates, this masks the magnitude of the error, but at least this is a simple comparison.

Now if the variations between the tracer and the Hi-Flow were due to random experimental errors, then we'd expect roughly 50% of the sites to have tracer greater than Hi-Flow, and 50% lower. It's actually a 70/30 split, but the remarkable thing is that we can predict which region will have tracer greater than Hi-Flow and which won't. This is pretty much the same thing as me being able to walk into a bar and betting the barmaid that if I stand on her side of the bar and flip a coin it will always

come up heads, but if I stand on my side of the bar and flip a coin, it will always come up tails. And in between drinks, we run that experiment, and it turns out that I'm right 16 out of 17 times.

Now that's a bar bet I'd like to be able to make routinely.

You also said in your unpublished comment to ESE that the testing I conducted on your instrument and others in March of 2013 showed a low occurrence of this problem. That's true of course, but I was surprised you said that, since you know that immediately after we did that testing that I met with some very experienced Hi-Flow technicians who specifically told me that they had fixed some of their samplers that had been reporting leaks too low by upgrading the sampler's software. Since all of the samplers we tested when we tested yours had new generation software, the only real surprise is that we saw any failure at all, and that failure was in your sampler. So even though new software improves the problem, it doesn't fix it completely. Additionally, there are lots of these samplers around the US and the world using older software, and lots of data that has been collected using samplers prior to software upgrades.

One other argument you made was that your Phase I pneumatic data, made by Hi-Flow, was higher than your Phase II pneumatic data, collected by meter, and if your Hi-Flow had been reporting too low, this should have been the other way around. The reason this isn't true is that your Phase I pneumatic data is clearly an emitter data set (95% of them are emitting) while your Phase II data set is a comprehensive data set (about 21% are actual emitters). So you accidentally excluded sampling zero emitters in Phase I, which biases that data high by a factor of four to five, and offsets any Hi-Flow sensor failure. Additionally, the Phase II data actually shows exactly what I predicted to you it would show -- that the high emitters are more predominant at sites with lower methane compositions when measured by the inline meter as opposed to your Phase I measurements, where the sensor failure caused the high emitters at those sites to be under reported.

In any case, I think this shows that it probably would have been better to involve me directly in discussions you had with the EDF committees and others about this problem after I brought it to you in October of 2013, because I could have explained immediately why the reasons you thought this problem didn't affect your Phase I data were incorrect. It has been puzzling to me that given the overwhelming evidence, that this problem wasn't obvious to you, but I'm wondering if that might be due to inexperience with field measurements. As an example, in both your Phase I and Phase II papers, you incorrectly describe the operation of the Hi-Flow sensors, and without understanding that the Hi-Flow has to to switch back and forth between sensors to make accurate measurements, it's probably impossible for you to understand the sensor transition problem.

I'm wondering if inexperience might have also led to the problems in your Phase II

work as well. It's a harsh environment for meters to be transported between field sites on rough roads and have raw natural gas run through them, and I think most people with experience in field measurements would have built in a routine testing of those meters during the project, rather than just check them before and after the project as you did. When you're out in the field looking at pneumatics, you see lots of them with oil or other hydrocarbon accumulations, so it's easy to picture how the meter sensor could get fouled, as yours did. I would think at least a weekly multi-point meter calibration and a daily single point flow check would be required to ensure accurate measurements. which is what was done during the EDF WSU distribution work. The Indaco Hi-Flows that were used in that project have a very similar flow measurement system to your Fox meter, which is a thermal element in a tube, and even though the distribution study was a much less harsh environment, where leaks of relatively clean distribution gas were measured and the flow system dilutes those leaks with air before the gas hits the sensors, full scale weekly calibrations and single point daily flow checks were conducted.

Now, as you remember, while that project was ongoing, I found that one of your two primary meters was measuring too low by a factor of three. Well, that's not a surprise, given the harsh environment. I haven't used the particular meter that you were using before, but I did look at the manual for it, and it clearly states that a dirty sensor will cause measurements to be too low.

But I think how you addressed that issue indicates further inexperience. Since you don't mention the meter test I made showing it was a factor of three too low in your paper, but only indicate that you found the problem post project, it appears that you just kept using the meter, without trying to figure out what was wrong with it, and without instituting any additional meter checks.

Instead, it wasn't until the end of the project that you did any further checks, and at that point the response of the meter had changed again, to being low by about 34%. In order to understand more about the problem, you tried to use your Hi-Flow data to validate the meter results. Now your laboratory comparisons of the two for the most part are excellent and agree within 10%. But surprisingly, your field comparisons of the Hi-Flow to the meters are far worse. For measurements where either one or the other was >0.5 scfh, only 4 out of 19 (21%) are within 25%, and even for measurements >6 scfh, only 3 out of 10 (30%) are within 25% of each other. You do allude to the possibility of leaks affecting the measurements but don't give any indication that you tried to quantify the leaks that you think affected the measurements.

For comparison, in the WSU distribution work, where direct and tracer measurements were compared, 10 out of 14 (71%) were within 50% of each other, over a range of about 0.6 to 56 scfh. Now I would have liked that to be better, but I think I understand some of the challenges, one being that some of those that are far off are at really low emission rates, so missing just one source could throw you off a lot. But keep in mind, that's measuring the whole M&R facility or an underground leak, and comparing it to a

downwind tracer flux measurement, so you have lots of challenges including multiple measurements at the facility and tracer source configurations.

But for your pneumatic work, while doing a direct comparison of Hi-Flow to meters, for just single sources, only 7 of 19 (37%) were within 50% of each other over a similar emission range of 0.5 to 60 scfh.

So unfortunately your comparison of High Flow to meters should not have been used to justify correcting your meter, especially when my direct test of that meter's performance mid-project showed it was much worse than the post project check indicated.

Another indication of the meter uncertainty came from Matt Harrison, who was present when I found that your meter was reading a factor of three too low, and said at the time, "Yeah, everyone knows that meter is flaky. You can hook it up to an pneumatic and hear the pneumatic fire but not see anything on the meter."

Now, along with the sensor getting dirty, your meter measurements might have been affected by two other factors mentioned in the meter manual. These meters are supposed to be oriented upright, and you need a certain length of straight run (I think for the meter you were using, six inches) before the meter. However, it appears, looking at a slide from the presentation about the project on your website shown below, that those conditions weren't met either. Although you can see in the close up that the meter is marked with a label that says "Keep Upright and Level", that condition hasn't been met in either configuration pictured. Additionally, the entrance length doesn't appear to meet the required distance either.

<Upside Down Meter 1.jpg>

<Upside Down Meter Close-up.jpg>

I think these issues were all compounded by perhaps your lack of experience with what information editors and reviewers need to evaluate field measurement papers. Your meter problem is only mentioned in a footnote on page 59 of your Supplementary Information, and was likely missed by the editor and reviewers. But if reviewers with substantial field experience understood the entire picture -- that you only checked your calibration before and after the project, that there was an undisclosed mid project test showing meter performance was much worse than the correction you applied, that after you were shown one meter was faulty in the middle of the project that you simply continued to use it without finding out what was wrong or instituting improved

calibration checks, "that everyone knew that meter was flaky," and that your Hi-Flow and meter field measurements don't compare very well -- I believe they would conclude that you didn't meet the fundamentals of quality assurance and that the paper would have been rejected.

So unfortunately neither the Phase I or Phase II data should be used by EPA. Although there may be large uncertainties in inventories, we shouldn't include numbers that have such large question marks. Think about cancer treatments. Those have very uncertain outcomes, but that doesn't mean that we don't want good quality assurance in cancer research or in the dosages of drugs or radiation therapy that are used. And when you consider the broad environmental impact of air toxics to the communities surrounding oil and gas facilities as well as the consequences of climate change, it's critical that we use the best data possible.

And as I said at the start, safety is my biggest concern regarding the HiFlow sensor failure, and I think perhaps again inexperience has caused you not to fully appreciate what a critical safety issue this is. I've spent a lot of time measuring leak rates at natural gas facilities, and I've seen facility personnel shut down units in order to address large leaks that we found due to safety concerns -- I've done lots of leak measurement programs that were focused more on the integrity of the facility rather than the issue of greenhouse gases. Additionally, we don't know how the sampler might be used in the future -- for instance, given GTI's and WSU's work in distribution, it might be used to rank leaks for repair in that segment (even though the WSU study used a different version of the sampler not affected by this problem).

James Reason wrote a really great book about the Swiss cheese theory of disasters (Reason, James (1997). Managing the risks of organizational accidents. Aldershot: Ashgate. ISBN 1840141042.) which is widely studied in aviation, engineering, and the fire service. In it he describes how the really terrible things that happen usually occur because there have been failures on several levels, and those failures line up to let something really bad happen.

We had a terrible example of that happen here in North Carolina a couple of years ago. A couple checked into a hotel, and the next morning they were dead. Seven weeks later, an 11 year old boy died in the same room, and although his mother survived, she had permanent brain damage.

All of that could have been avoided, because they were killed by carbon monoxide. You might have seen this on 20/20:

http://abcnews.go.com/US/north-carolina-best-western-room-225-open-deaths/story?id=21564280

Here's how it all lined up:

- 1) The hotel pulled an old pool heater out of another property and installed it at that hotel, even though it was at the end of its life, meaning it was inefficient and was at risk for producing more carbon monoxide, and they didn't get a city inspection permit;
- 2) The vent pipe was corroded, and let the CO escape under the room where everyone was killed:
- 3) There were holes in the fire place in the room that let more CO in that would have come in otherwise;
- 4) The CO detectors that were supposed to have been installed in the rooms were actually natural gas detectors, installed by mistake.

So that's what killed the first couple.

But here's why the little boy died:

- 1) Three days after the couple was killed, a family in the room above got really sick, and complained, but the hotel didn't pay attention;
- 2) The family of the first couple raised warnings with the hotel and police that it might be CO and again no one paid attention;
- 3) The medical examiner didn't visit the scene of the first couple and see that the wife had thrown up (an important clue in CO poisoning)
- 4) He also didn't put an expedite order on their blood work, so it sat for 40 days (two people simultaneously dead in an enclosed space -- a huge alarm bell for some toxic substance, especially CO);
- 5) He finally got the results four days before the child died in the room, but;
- 6) He sat on them for a week and by the time he finally sent them out to the local police; the child was had been killed and his mother permanently injured.

That's a tragic story, all right. And as you can imagine, the two families are suing everyone in sight that had anything to do with any of that, and I would too if I had lost a family member. Meanwhile, the DA also charged the head of the hotel management group with three counts of manslaughter, and all of those cases are still on going.

That's just one example of how tragic things can happen when we don't do everything possible to ensure people's safety. But if you do just a little bit of research, you'll see how frighteningly common that is.

So I know you'll want to address the Hi-Flow sensor failure issue immediately.

As I suggested at the start, let's do it this week. I can go up and meet with EPA tomorrow or Friday, and if you can't be there in person, you can call in, and you can have any interested parties from EDF or your production committees call in as well. i know everyone's busy, but this won't take more than an hour, and I think we should all be willing to make that much time for such a critical issue.

Just	let me	know	when	the	best	time	for	all	of yo	u is.
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Thanks,

Touche'

<Howard Energy Science and Engineering Analysis of UT Data Set 2015.pdf>

<ES&T Comment on Allen et al. Methane Emissions from Process Equipment.pdf>

<Dave Allen Response to ES&T Letter.pdf>

<Touche Response to Dave Allen Comment in ESE Submitted 09\_10\_2015.pdf>

To: GHGInventory[ghginventory@epa.gov]; RAlvarez@edf.org[RAlvarez@edf.org]; Rees,

Jeff[Jeff.Rees@pxd.com]; Dave Allen[allen@che.utexas.edu]; Lisa

Song[lisa.song@insideclimatenews.org]; Weitz, Melissa[Weitz.Melissa@epa.gov]; McKittrick,

Alexis[McKittrick.Alexis@epa.gov]

From: Touche Howard

Sent: Thur 2/18/2016 10:02:33 PM

Subject: Re: Updates under Consideration for Production and Gathering and Boosting in the GHG

Inventory

Howard 2015 Energy Science and Engineering Analysis of Allen et al 2013.pdf

Howard ES&T Comment on Allen et al. 2014 Methane Emissions from Process Equipment.pdf

Dave Allen Response to ES&T Letter.pdf

Touche Howard Response to Dave Allen ESE Rebuttal (Rebuttal Withdrawn by Allen).pdf

#### Dear Ms. Weitz:

This email is a response to your request for feedback on your draft proposed revision to production segment emissions, in particular for "feedback on other data sources (e.g., Allen et al.2013 and 2014, the Prasino Group 2013) that could be considered for the development of emission factors for equipment leaks and/or pneumatic controllers."

I would like to reiterate my concerns about the Allen et al. 2013 and 2014 studies that we discussed during our meeting on February 5. As you are aware, the Bacharach Hi-Flow Sampler has been demonstrated to fail to transition from its low scale to its high scale sample concentration sensor. As a result, the Bacharach sampler can under report emission rates by orders of magnitude. As I reported in Howard (2015) (attached), this sensor failure affected the Bacharach data collected by Allen et al. (2013), and therefore that data (including data for equipment leaks and pneumatic controller emissions) should not be used for the EPA GHG inventory.

An additional problem with the pneumatic controller data in Allen et al. (2013) is that it was not a random sample, as intended, but inadvertently focused almost completely on devices that were emitting. This possibility was acknowledged by Allen et al. (2014), where intermittent devices were emitting less than 20% of the time, compared to Allen et al., (2013) where intermittent devices were were emitting over 95% of the time. Consequently, the pneumatic device data in Allen et al. (2013) would over report emission rates since zeroes were excluded, although some of this over reporting may have been offset by the sensor failure in the Bacharach sampler.

Both the Prasino (2013) and Allen et al. (2014) studies relied on installing flow meters in the pneumatic device supply gas line, which required the supply gas to be turned off and then back on. This may have reset some of the poorly behaving controllers which could be the highest emitters, causing the reported data to be biased too low. Unfortunately, no before and after measurements using a non-intrusive method were made in either study to examine this possibility.

Additionally, the Allen et al. (2014) study had meter calibration problems that were not fully disclosed. The study team only checked the calibration of their Fox flow meters before and after the project. However, flowing raw natural gas through flow meters presents a very challenging environment. Many of the sites sampled had significant amounts of heavier hydrocarbons in the natural gas which is often observed to foul pneumatic devices, so it's quite likely that the meters might become dirty during measurements, and the Fox meter manual specifically states that if the meter element becomes dirty that the meter will read too low.

I tested the two meters used by Allen et al. (2014) in March of 2014 while that project was on-going. This test was conducted in the presence of two authors of that study (Matt Harrison and Adam Pacsi) as well as the chair of that study's EDF Technical Working Group, Carrie Reese. At that time, I found one meter to be reading too low by a factor of 2.8.

However, Allen et al. (2014) did not disclose this test and only note in a footnote in their Supplementary Information that at the end of the project that they found one meter to be dirty and that it needed a correction factor of 1.52. They justified when to start applying this correction factor by comparing a limited number of Bacharach Hi-Flow measurements to the Fox flow meter measurements. Unfortunately, as seen in the graph below, this subset of data overall shows very poor agreement between the two methods. Even for measurements where one method or the other indicated a flow rate greater than 3 scfh (where both the Fox flow meters and the Bacharach Hi-Flow Sampler should be able to make accurate measurements), less than half of the measurements agree within 50%, and over half disagree by more than a factor of four. Consequently, these results should not have been relied on to assess when to apply a correction factor or to determine that either meter maintained a stable calibration.

Finally, the failure of Allen et al. (2014) to disclose the tests that I conducted showing that their meter calibration problems were far worse than they reported indicates that these authors did not understand the information required by editors, reviewers, and readers to assess the validity of their data set, and leaves open the possibility that they may have failed to report other problems as a result of that lack of understanding.

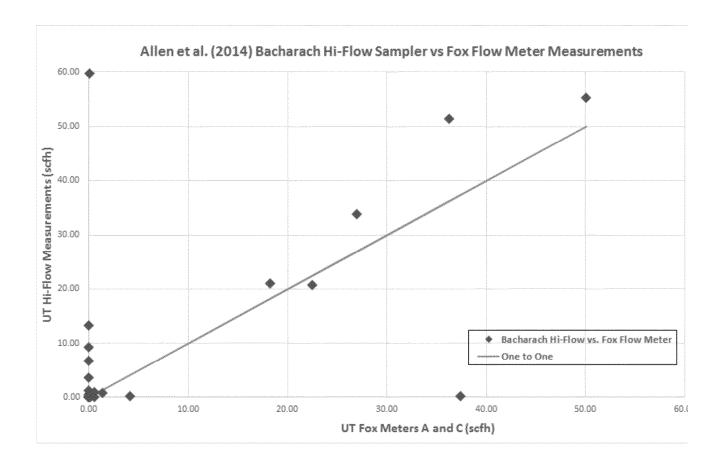
If you have any questions about those meter tests, you might consider contacting Carrie Reese at Pioneer Natural Resources (<a href="mailto:Carrie.Reese@pxd.com">Carrie.Reese@pxd.com</a>) who as I noted above was on-site during the testing and witnessed the meter problems. You might also contact Ramon Alvarez at the Environmental Defense Fund (RAlvarez@EDF.org) who was EDF's representative for this project. Ms. Reese told me that she reported the results of the meter tests to Dr. Alvarez, so it might be helpful to ask him why he thought it was appropriate for this information to be withheld.

I have also attached my response to Professor Allen's rebuttal to Howard (2015) which he subsequently withdrew before publication, and our exchange of letters to ES&T regarding the problems with the Allen et al. (2014) study.

Please let me	know if you	have any qu	uestions.

Regards,

Touche'



On Wed, Feb 3, 2016 at 5:50 PM, GHGInventory <ghginventory@epa.gov> wrote:

Dear Colleagues,

Thank you for your comments on updates under consideration for the distribution and transmission and storage segments in the GHG Inventory.

Memos on updates under consideration for production and gathering and boosting in the GHG Inventory are now available, and EPA is seeking your expert review of those updates under consideration.

The Production memo is available at <a href="http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_Production\_report/DRAFT\_Proposed\_Revision\_to\_Production\_report/DRAFT\_Proposed\_Revision\_to\_Production\_report/DRAFT\_Proposed\_Revision\_to\_Production\_report/DRAFT\_Proposed\_Revision\_to\_Production\_report/DRAFT\_Proposed\_Revision\_to\_Production\_report/DRAFT\_Proposed\_Revision\_to\_Production\_report/DRAFT\_Proposed\_Revision\_to\_Production\_report/DRAFT\_Proposed\_Revision\_to\_Production\_report/DRAFT\_Proposed\_Revision\_to\_Production\_report/DRAFT\_Proposed\_Revision\_to\_Production\_report/DRAFT\_Proposed\_Revision\_report/DRAFT\_Proposed\_

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3-2016.pdf.

The Gathering and Boosting memo is available at <a href="http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemissions/usinventoryreport/DRAFT\_Proposed\_Revision\_to\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_to\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_to\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_to\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_to\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_to\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_NG\_Gather-16">http://www.nc.com/climatechange/ghgemission\_NG\_Gather-16">http://www

EPA requests that stakeholders submit comments by February 18, 2016 to <a href="mailto:ghginventory@epa.gov">ghginventory@epa.gov</a>. We appreciate your efforts to provide comments within this timeframe, as it will allow us time to incorporate your feedback into the upcoming GHG Inventory. We will review and consider--for this year's GHG Inventory as possible, or future GHG inventories--feedback received after the deadline for the production and gathering and boosting memos, and also for the previously released transmission and storage and distribution memos.

Thank you again for your feedback on natural gas and petroleum systems in the GHG Inventory.

Best regards,

Melissa

Melissa Weitz

Climate Change Division

U.S. Environmental Protection Agency

(202) 343-9897

Weitz.Melissa@epa.gov

ED\_001785E\_00002386-00005



Correspondence/Rebuttal

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## Response to Comment on "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers"

oward<sup>1</sup> has provided comments on our report of methane emissions from pneumatic controllers at natural gas production sites.<sup>2</sup> We disagree with the assertions made in the comment. The assertions include claims regarding sampling methods and comparisons with other measurement studies. We respond to each of these assertions below.

#### SAMPLING METHODS

The primary assertions in the comment deal with our sampling method and claim (1) sensor failure in our Hi-Flow instrument, (2) faulty flow meters, and (3) resetting of malfunctioning pneumatic controllers when we inserted flow meters to conduct

(1) Sensor failure in the Hi-Flow instrument refers to a potential failure of the HiFlow sampler to change between its catalytic oxidation and thermal conductivity measurement modes at approximately 5% hydrocarbon concentration (~24 scf/h vent rate). To assess whether this potential crossover failure impacted measurements in Allen et al.,2 or our earlier work employing the instrument, we conducted laboratory testing, field testing, and additional analyses of field data.

Laboratory Testing: As documented in the Supporting Information for Allen et al.,2 prefield deployment laboratory testing of the sampler used in our work (referred to here as the University of Texas (UT) HiFlow sampler) demonstrated successful crossover between the two measurement modes for methane and a wet gas surrogate (70.5% methane

Field Testing: The study team participated in a twoday field test of several HiFlow samplers. Participants in the field testing included our team, the commenter, a consulting firm, an instrument provider and consulting firm, and a natural gas producer. During this field test, the UT HiFlow sampler successfully crossed-over on sites with methane concentrations in the produced gas ranging from 77%-91%. Over 2 days of testing, the UT HiFlow sampler crossed-over successfully in all but one test; that test occurred at a site with a produced gas containing 91% methane. Subsequent examination of the instrument indicated that it had lost calibration after losing power, then being restarted by personnel not on our study team. The sampling protocol in Allen et al.2 required a calibration check each time the HiFlow sampler was turned on. Once the calibration protocol was followed, the HiFlow sampler resumed proper

Additional Analysis of Allen et al.3 Data: Infrared (IR) video camera scans were taken on some sites during field work for Allen et al.,3 including for 118 of the 305 pneumatic controllers (39%) sampled in that work. These infrared camera scans were done immediately upon arrival at the site and thus were not exactly contemporaneous with the UT HiFlow measurements. Nevertheless, if the crossover problem were to have been prevalent, then the expectation would be to find infrared camera scans for which large leaks were detected by the IR camera but not measured by the UT HiFlow sampler. From this subset of data, 5 of the 118 devices had detectable emissions in the IR camera scan that were not captured by the subsequent UT HiFlow measurement. However, 7 of the 118 devices without detected emissions in the IR scan were found to have emissions between 0.2 and 5.0 scf/h by the UT HiFlow sampler. A likely explanation for these differences, based on the measurements we report in Allen et al.2 (see Figure 1 in that publication), is the intermittent venting pattern of some pneumatic controllers. Because of intermittent venting, some controllers would be expected to vent while being observed by the IR camera, but not when later being observed by the UT HiFlow sampler, and vice versa. Overall, the comparison with IR camera data suggests that the UT HiFlow sampler was capturing the emissions from pneumatic controllers in its measurements.

From these laboratory measurements, field measurements and additional analyses, we conclude that sensor failure did not significantly impact the measurements made with the UT HiFlow sampler in either Allen et al.  $^{2}$  or Allen et al.  $^{3}$ 

(2) The assertion of faulty flow meters refers to the readings of the flow meters being affected by deposits on the thermal conductivity sensor that could occur during the field campaign. These flow meters were inserted into the supply gas line of the pneumatic controllers during the field campaign and were the primary source of data in Allen et al.2 While not anticipated prior to the study, our observations in the field revealed that the supply gas to some controllers had the potential to create deposits, which can lead to controller malfunction as well as deposits on flow meters inserted into controller supply gas lines. Poststudy testing revealed that these deposits did occur on one of our flow meters (designated Fox A), but not the other two meters (Fox B and C). Because we were making measurements using both the UT HiFlow sampler and the flow meters for a subset of controllers in the field, we were able to identify the site at which a step change



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occurred in the flow measurement performance of the Fox A meter, due to deposits on the thermal conductivity sensor. We applied a correction factor, based on pre- and poststudy testing done in our laboratory, to the flow rate measurements made by the Fox A meter after the deposits occurred. This adjustment was documented in the data set we reported in the Supporting Information (Section S4, particularly Table S4-4) for Allen et al.<sup>2</sup> In the Supporting Information, we describe the adjustment and flag every controller measurement to which the adjustment was applied. Thus, we believe that we have corrected for the impact that deposits on one of the flow meters had on our measurements, in a transparent and well-documented

(3) Resetting of malfunctioning pneumatic controllers refers to potential alteration of pneumatic controller behavior due to the insertion of the supply gas meter. While this cannot be ruled out as a possibility, we have no evidence that this occurred. We believe that we minimized the potential for this behavior by having a site operator, familiar with the site and the controllers (rather than the study team), insert the flow meter, while the study team observed the process. If there were a high pneumatic controller bleed rate that became low or zero after the connection, this should have been observable by the company operator and the field team through the audible venting of the controller. After the flow meter was inserted, the study team waited approximately 5 min before collecting flow measurement data.

#### COMPARISON WITH OTHER MEASUREMENT STUDIES

The comment makes comparisons between the data reported in our field work<sup>2</sup> and measurements reported in previous measurements by our team<sup>3</sup> and measurements made by a study conducted in British Columbia and Alberta.4 We caution against making direct comparisons without correcting for differences in sample sets and the way in which controllers are classified. We note that while our work<sup>2</sup> sampled all controllers at conventional and unconventional natural gas well sites in many production regions, the Canadian study was conducted in only one production region and selected controllers with manufacturer reported bleed rates in excess of 4.2 standard cubic feet per hour (scf/h). The Allen et al.3 study sampled only relatively young wells producing from shale formations. In addition, classifications of controllers (such as intermittent) can be done based measured emissions from the controllers (as in Allen et al.2) or based on the design of the controller (as in the Canadian study and our earlier work<sup>3</sup>), and there is a high degree of variability in these classifications. We have described these differences in our report,2 identifying and correcting for these sampling differences, and will not repeat those comparisons here. We emphasize, however, that such comparisons must be done with caution. The comparisons in the comments do not appear to have accounted for the differences in sample populations.

David T. Allen\*,† David W. Sullivan<sup>†</sup> Matt Harrison<sup>∓</sup>

<sup>†</sup>Center for Energy and Environmental Resources, University of Texas at Austin, 10100 Burnet Road, Building 133, M.S. R7100, Austin, Texas 78758, United States

<sup>‡</sup>AECOM (formerly URS Corporation), 9400 Amberglen Boulevard, Austin, Texas 78729, United States



#### **AUTHOR INFORMATION**

Corresponding Author \*E-mail: allen@che.utexas.edu.

The authors declare the following competing financial interest(s): Lead author David Allen has served as chair of the Environmental Protection Agencys Science Advisory Board (2012-2015), and in this role was a paid Special Governmental Employee. He is also a journal editor for the American Chemical Society and has served as a consultant for multiple companies, including Eastern Research Group, ExxonMobil, and Research Triangle Institute. He has worked on other research projects funded by a variety of governmental, nonprofit and private sector sources including the National Science Foundation, the Environmental Protection Agency, the Texas Commission on Environmental Quality (TCEQ), the American Petroleum Institute and an air monitoring and surveillance project that was ordered by the U.S. District Court for the Southern District of Texas. David Sullivan has worked on other research projects funded by the TCEQ, the California Air Resource Board, the Texas Air Research Center, and the U.S. District Court for the Southern District of Texas. Matt Harrison, who worked for URS at the time of the paper publication, is now an employee of AECOM, a company that purchased URS. Financial support for the original report<sup>2</sup> was provided by the Environmental Defense Fund (EDF), Anadarko Petroleum Corporation, BG Group plc, Chevron, ConocoPhillips, Encana Oil & Gas (U.S.) Inc., Pioneer Natural Resources Company, SWEPI LP (Shell), Southwestern Energy, Statoil, and XTO Energy, a subsidiary of ExxonMobil. Funding for EDF's methane research series, including the University of Texas study, is provided for by Fiona and Stan Druckenmiller, Heising-Simons Foundation, Bill and Susan Oberndorf, Betsy and Sam Reeves, Robertson Foundation, Alfred P. Sloan Foundation, TomKat Charitable Trust, and the Walton Family Foundation.



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# **Energy Science & Engineering**

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RESEARCH ARTICLE

# University of Texas study underestimates national methane emissions at natural gas production sites due to instrument sensor failure

Touché Howard

Indaco Air Quality Services, Inc., Durham, North Carolina

#### Keywords

Greenhouse gases, methane, natural gas

#### Correspondence

Touché Howard, Indaco Air Quality Services, Inc., Durham, NC. Tel: (919) 943-9406; E-mail: touche.howard@indacoaqs.com

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#### Abstract

The University of Texas reported on a campaign to measure methane  $(CH_A)$ emissions from United States natural gas (NG) production sites as part of an improved national inventory. Unfortunately, their study appears to have systematically underestimated emissions. They used the Bacharach Hi-Flow® Sampler (BHFS) which in previous studies has been shown to exhibit sensor failures leading to underreporting of NG emissions. The data reported by the University of Texas study suggest their measurements exhibit this sensor failure, as shown by the paucity of high-emitting observations when the wellhead gas composition was less than 91% CH<sub>4</sub>, where sensor failures are most likely; during follow-up testing, the BHFS used in that study indeed exhibited sensor failure consistent with under-reporting of these high emitters. Tracer ratio measurements made by the University of Texas at a subset of sites with low CH4 content further indicate that the BHFS measurements at these sites were too low by factors of three to five. Over 98% of the CH 4 inventory calculated from their own data and 41% of their compiled national inventory may be affected by this measurement failure. Their data also indicate that this sensor failure could occur at NG compositions as high as 97% CH<sub>4</sub>, possibly affecting other BHFS measurement programs throughout the entire NG supply chain, including at transmission sites where the BHFS is used to report greenhouse gas emissions to the United States Environmental Protection Agency Greenhouse Gas Reporting Program (USEPA GHGRP, U.S. 40 CFR Part 98, Subpart W). The presence of such an obvious problem in this high profile, landmark study highlights the need for increased quality assurance in all greenhouse gas measurement programs.

#### Introduction

The climatic benefits of switching from coal to natural gas (NG) depend on the magnitude of fugitive emissions of methane ( $\mathrm{CH_4}$ ) from NG production, processing, transmission, and distribution [12, 13, 27]. This is of particular concern as the United States increasingly exploits NG from shale formations: a sudden increase in  $\mathrm{CH_4}$  emissions due to increased NG production could trigger climate "tipping points" due to the high short-term global warming potential of  $\mathrm{CH_4}$  (86× carbon dioxide on a 20-year time scale) [19]. The United States Environmental

Protection Agency (USEPA) estimates  $\mathrm{CH_4}$  emissions from the NG supply chain by scaling up individual ground-level measurements, mostly collected by reporting from industry [26]. However, some recent studies have questioned whether these "bottom-up" inventories are too low, since airborne measurements indicate that  $\mathrm{CH_4}$  emissions from NG production regions are higher than the inventories indicate [5, 14, 17, 20, 21].

In order to help determine the climate consequences of expanded NG production and use, and to address the apparent discrepancy in top-down and bottom-up measurements, the University of Texas (UT) at Austin and the

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UT Study Underestimates Methane Emissions

Environmental Defense Fund launched a large campaign to measure CH4 emissions at NG production sites in the United States [1]. This study used both existing EPA GHG inventory data and new measurements to compile a new national inventory of CH<sub>4</sub> emissions from production sites. Forty-one percent of this new inventory was based on measurements made by [1], which included measurements of emissions from well completion flowbacks as well as measurements of emissions from chemical injection pumps, pneumatic devices, equipment leaks, and tanks at 150 NG production sites around the United States already in routine operation (measurements from tanks were not used for inventory purposes). However, the measurements of emissions at well production sites already in operation (which comprised 98% of the new inventory developed by [1]) were made using the Bacharach Hi-Flow Sampler (BHFS; Bacharach, Inc., New Kensington, PA) and recent work has shown that the BHFS can underreport individual emissions measurements by two orders of magnitude [10]. This anomaly occurs due to sensor transition failure that can prevent the sampler from properly measuring NG emission rates greater than ~0.4 standard cubic feet per minute (scfm; 1 scfm =  $1.70 \text{ m}^3 \text{ h}^{-1}$  or  $19.2 \text{ g min}^{-1}$  for pure CH<sub>4</sub> at 60°F [15.6°C] and 1 atm; these are the standard temperature and pressure used by the U.S. NG industry). Although this failure is not well understood, it does not seem to occur when measuring pure CH<sub>4</sub> streams, but has been observed in four different samplers when measuring NG streams with CH4 contents ranging from 66% to 95%. The sampler's firmwareversion and elapsed time since last calibration may also influence the occurrence of this problem [10, 18].

This paper presents an analysis of the UT [1] emissions measurements that were made with the BHFS, and shows that high emitters (>0.4 scfm [0.7  $\rm m^3~h^{-1}$ ]) were reported very rarely at sites with a low CH<sub>4</sub> content in the well-head gas (<91%), consistent with sensor transition failure. It also details testing of the exact BHFS instrument used in that study and shows the occurrence of this sensor failure at an NG production site with a wellhead composition of 91% CH<sub>4</sub> (the highest CH<sub>4</sub> concentration site available during testing). Finally, the downwind tracer ratio measurements made by [1] at a subset of their test sites are reexamined and indicate that the BHFS measurements made at sites with low wellhead CH<sub>4</sub> concentrations were too low by factors of three to five.

## **Evidence of BHFS Sensor Transition Failure in the UT Dataset**

The Allen et al. [1] UT dataset is unique due to the large number of BHFS measurements made across a wide geographic range, the variety of emissions sources

(equipment leaks, pneumatic devices, chemical injection pumps, and tanks) and the wide range of NG compositions (67.4–98.4%  $\mathrm{CH_4})$  that were sampled. As such, the UT study provides an important opportunity to evaluate the occurrence of sensor transition failure in the BHFS as well as the impact of this issue on emission rates and emissions factors based on measurements in other segments of the NG supply chain.

The BHFS uses a high flow rate of air and a loose enclosure to completely capture the NG-emitting from a source, with the emission rate calculated from the total flow rate of air and the resulting sample NG concentration, after the background NG concentration is subtracted. The sampler uses a catalytic oxidation sensor to measure sample concentrations from 0% to 5% NG in air, but must transition to a thermal conductivity sensor in order to accurately measure sample concentrations higher than 5%. It is the failure of the sampler to transition to the higher range that has been previously observed by Howard et al. [10] and which can prevent the sampler from correctly measuring emission rates larger than 0.3–0.5 scfm (0.5–0.9 m³ h<sup>-1</sup>) (corresponding to sampler flow rates of 6–10 scfm [10–17 m³ h<sup>-1</sup>]). Figure 1 summarizes data

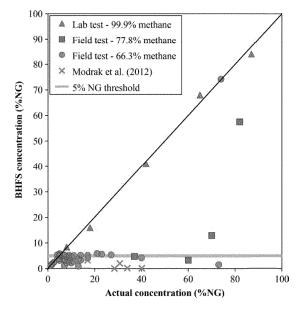


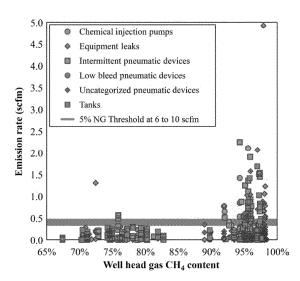
Figure 1. Occurrence of sensor transition failure in BHFS instruments with natural gas of varying CH<sub>4</sub> content from field and lab testing and from emission measurement studies (data from [10, 18]). NG concentrations in the BHFS sampling system measured by the BHFS internal sensor are compared to independent measurements of the sample NG concentrations. The 5% NG sample concentration threshold is the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity. BHFS, Bacharach Hi-Flow Sampler; NG, natural gas.

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showing the occurrence of sensor transition failure in several BHFS instruments during both fieldand laboratory testing as well as an example of the failure that occurred during an emission measurement study [10, 18].

Figure 2 presents the BHFS emission measurements from [1] as a function of percent  $CH_4$  in wellhead gas at each site. Figure 2 also shows a line corresponding to emission rates of 0.3–0.5 scfm (0.5–0.9  $\mathrm{m}^3$   $\mathrm{h}^{-1}$ ), which represents the range of emission rates that would require transition from the catalytic oxidation sensor to the thermal conductivity sensor at sample flows ranging from 6 to 10 scfm (10–17  $\mathrm{m}^3$   $\mathrm{h}^{-1}$ ).

As seen in Figure 2, there are very few measurements in the thermal conductivity sensor range (above  $\sim 0.4$  scfm  $[0.7 \text{ m}^3 \text{ h}^{-1}]$ ) at sites where the wellhead gas composition of CH<sub>4</sub> is less than 91%, and this is true across all source categories. Raw data for sample flowand concentration from the BHFS were not provided in [1] supplemental information, so for this analysis, an average BHFS sample flowrate of 8 scfm (14 m  $^3$  h $^{-1}$ ) has been assumed, which is the lower of the two sampling flows specified by the Bacharach operating manual [4]. At this sample flowrate, an emission source of 0.4 scfm (0.7 m $^3$  h $^{-1}$ ) corresponds with a sample concentration of 5% NG in air, above



**Figure 2.** Emission rates of various sources measured by BHFS at NG production sites versus CH  $_4$  concentration of the wellhead gas (data from [1]). The solid line indicates the maximum emission rate that could be measured by the catalytic oxidation sensor only (i.e., in the case of sensor transition failure). For sites with a NG composition greater than 91% CH $_4$ , 13.3% of the measurements are in the TCD sensor range, assuming a sampler flow rate of 8 cubic feet per minute. For sites with less than 91% CH $_4$ , only 1.5% of the measurements are in the TCD range. BHFS, Bacharach HiFlow Sampler; NG, natural gas; TCD, thermal conductivity detector.

which point the sampler would need to transition to the thermal conductivity sensor to allow for accurate measurements. For sites with  $\mathrm{CH_4}$  concentrations less than 91%, only four out of 259 measurements (1.5%) exceeded 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>), while for sites with CH<sub>4</sub> concentrations greater than 91%, 68 out of 510 measurements (13.3%) exceeded 0.4 scfm  $(0.7 \text{ m}^3 \text{ h}^{-1})$ . Consequently, there were almost nine times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH $_4$  (Fig. 2). If the sample flow rate were 6 scfm (10 m $^3$  h $^{-1}$ ) (due to a flow restriction or reduced battery power), the threshold for transition to the thermal conductivity range would be 0.3 scfm (0.5 m<sup>3</sup> h<sup>-1</sup>); this would still mean that there were almost seven times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH<sub>4</sub> than at sites with >91% CH<sub>4</sub>. Although it is well known that a small percentage of NG emission sources account for most of the total emissions from any given population [9, 15, 25], it is unlikely that almost all the significant emitters at NG production sites would occur only at sites with well head gas compositions >91% CH, It is also unlikely that the emission rates of all of the source categories surveyed by [1], which had diverse emission mechanisms such as equipment leaks, pneumatic controllers, chemical injection pumps, and tanks, would all have a ceiling of ~0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) at sites with lower wellhead gas CH₄ concentrations. Consequently, the low occurrence of high emitters at sites with lower wellhead gas CH<sub>4</sub> concentrations in [1] indicates that sensor transition failure occurred at sites with CH<sub>4</sub> content <91% and is consistent with the BHFS sensor failure found by Howard et al. [10].

# Alternative Theories for the Emission Rate Pattern

Other possible causes of the emission rate pattern in the UT BHFS measurements were considered, including: regional operating differences at production sites; lighter gas densities resulting in higher emission rates; and improved detection of emissions by auditory, visual, and olfactory (AVO, e.g., [24]) methods at sites with heavier hydrocarbon concentrations.

#### Regional operating differences

Allen et al. [1] point out that air pollution regulations in Colorado which required installation of low bleed pneumatic devices in ozone nonattainment areas after 2009 might have led to lower emission rates in the Rocky Mountain region, which also had the lowest average concentration of  ${\rm CH_4}$  in the wellhead gas. However, if the

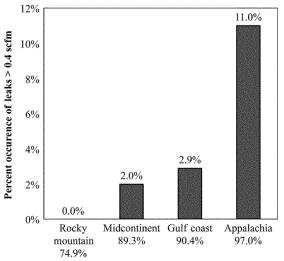
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UT Study Underestimates Methane Emissions

Rocky Mountain region is removed from the analysis, the occurrence of emitters >0.4 scfm (0.7 m³ h $^{-1}$ ) at sites with wellhead gas <91% CH $_4$  was still only four out of 129 measurements (3.1%), while for sites with CH $_4$  concentrations greater than 91%, there remain 68 out of 510 measurements (13.3%) that exceeded 0.4 scfm (0.7 m³ h $^{-1}$ ) (there were no Rocky Mountain sites with CH $_4$  >91%). Consequently, even if the Rocky Mountain region is removed from consideration, the occurrence of emitters >0.4 scfm (0.7 m³ h $^{-1}$ ) was almost four times less at sites with less than 91% CH $_4$  than at sites with greater than 91% CH $_4$ , so air quality regulations in Colorado do not appear to be the cause of the emission rate trend shown in Figure 2.

Beyond air pollution regulations, other unknown regional operating practices unrelated to  ${\rm CH_4}$  concentration might coincidentally cause the apparent relationship of site  ${\rm CH_4}$  concentrations with the occurrence of high emitters. However, as shown in Figure 3, the increase in leaks >0.4 scfm  $(0.7~{\rm m^3~h^{-1}})$  directly correlates with the increase in the average regional  ${\rm CH_4}$  concentration. Because there are four regions and two variables (site  ${\rm CH_4}$  concentration and the percent of leaks >0.4 scfm  $[0.7~{\rm m^3~h^{-1}}]$ ), the likelihood that regional operating characteristics would coincidentally cause the increase in occurrence of leaks >0.4 scfm  $(0.7~{\rm m^3~h^{-1}})$  to mirror the increasing regional site  ${\rm CH_4}$  concentration is only one in 24 (four factorial), or ~4%.



Region and average wellhead CH4 concentration

Figure 3. Occurrence of equipment leaks >0.4 scfm in each region of the [1] equipment leak data set. The odds of the occurrence of leaks >0.4 scfm being positively correlated with site CH <sub>4</sub> concentration are one in 24, which makes it unlikely this trend is due to regional operating effects.

Other known operating characteristics of the regions, such as average site pressure and average site age, are not related to the occurrence of equipment leaks >0.4 scfm (0.7 m $^3$  h $^{-1}$ ): average site pressures show no correlation, and average site age is negatively correlated with the occurrence of equipment leaks >0.4 scfm (0.7 m $^3$  h $^{-1}$ ).

Another argument against regional differences comes from the air quality study conducted by the City of Fort Worth ([6]; or the Ft. Worth study). Ft. Worth is part of the Mid-Continent region defined by [1], where the occurrence of equipment leaks only (as opposed to all BHFS measurement categories) >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) observed by [1] was 2.0% of the total equipment leaks in that region. However, equipment leaks >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) were 9.9% of the equipment leaks measured in the Ft. Worth study. This was determined using the Ft. Worth study categories of valves and connectors; their remaining category of "other", which included pneumatic control devices, had an even higher occurrence of sources >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) of 27.0%. Previous work [10] has shown that although sensor transition failure likely occurred in the Ft. Worth study, these incidents were limited compared to those in [1]. Consequently, the much lower occurrence of leaks >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) in the Mid-Continent region in [1] compared to the Ft. Worth study indicates that sensor transition failure was responsible for the low occurrence of emitters < 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) as opposed to regional differences.

#### Gas density

Wellhead gas with a lower  $\mathrm{CH_4}$  and a greater heavier hydrocarbon content will be denser than gas with higher  $\mathrm{CH_4}$  content. Since gas flow through an opening is inversely related to the square root of the gas density, streams with lower  $\mathrm{CH_4}$  content would have a lower flow rate if all other conditions were the same. However, this would cause at most a 20% decrease for the lowest  $\mathrm{CH_4}$ /highest heavier hydrocarbon streams compared to the highest  $\mathrm{CH_4}$ /lowest heavier hydrocarbon streams observed in the UT study. This would also result in a gradual increase in emissions as  $\mathrm{CH_4}$  content increased, as opposed to the dramatic increase in emissions observed over a very narrow range of  $\mathrm{CH_4}$  concentrations (Fig. 2).

#### **AVO** detection

AVO methods might improve for gas streams with a greater proportion of heavier hydrocarbons, since those streams would have greater odor and might leave more visible residue near a leak. However, Figure 4 presents the occurrence of emitters >0.4 scfm (0.7 m³ h $^{-1}$ ) as a function of site CH $_{\! 4}$  concentrations in the Appalachia

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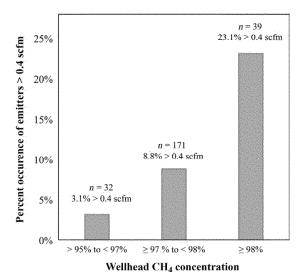


Figure 4. Occurrence of emitters >0.4 scfm as a function of site wellhead gas composition in [1] for the Appalachia region. An emission rate of greater than 0.4scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of 8scfm. The dramatic increase in emitters >0.4scfm over a narrow concentration range argues against the possibility that auditory, visual, and olfactory leak detection is the cause of the emission rate pattern seen in the [1] data set.

region alone. This region had the highest average CH<sub>4</sub> concentration in wellhead gas of any of the regions sampled in [1]. As seen in Figure 4, even over a very narrow range of site  $CH_4$  concentrations (from 95% to >98%  $CH_{A}$ ), there is a dramatic increase in emitters >0.4 scfm  $(0.7 \text{ m}^3 \text{ h}^{-1})$  with increasing CH<sub>4</sub> concentration. It is unlikely that AVO methods would become so much more efficient over such a narrow range of high CH 4 concentrations where the gas streams are likely odorless and would leave little residue. This dramatic increase in high emitters at sites with high CH<sub>4</sub> concentrations within the Appalachia region alone also argues against the previously discussed regional operating differences hypothesis in general, since this trend is within a single region. Additionally, although the Rocky Mountain region surveyed by UT [1] had the lowest average site CH<sub>4</sub> concentration (74.9%) and heaviest hydrocarbon content, it actually had the highest number of equipment leaks (of any size) per well of all the regions, and there were 25% more leaks per well in that region than in the Appalachia region, which had the highest average site CH<sub>4</sub> concentration (97.0%) and therefore the lowest heavier hydrocarbon content. If AVO methods were more effective due to the presence of heavier hydrocarbons, it seems unlikely the region with the heaviest hydrocarbon concentrations would have the highest rate of overall leak occurrences.

#### Field Testing of the UT BHFS

Because the trend in the [1] data was consistent with sensor transition failure in the BHFS and no other explanation seemed plausible, I partnered with UT to test the sampler used by [1]. During that field program, the UT sampler had a version of firmware earlier than version 3.03, and older firmware versions have been shown to exhibit sensor transition failure [10]. However, the possible effect of the sampler's firmware version on the sensor failure was not known before this testing of the UT sampler, and at the time of my testing its firmware had been upgraded to a custom version (3.04).

As previously explained, the BHFS uses a catalytic oxidation sensor to measure sample stream concentrations from 0% to  $\sim\!5\%$  NG, and a thermal conductivity sensor for concentrations from  $\sim\!5\%$  to 100% NG. The catalytic oxidation sensor is typically calibrated with 2.5% CH $_4$  in air and the thermal conductivity sensor is calibrated with 100% CH $_4$  [4]. The manufacturer recommends sensor calibration every 30 days, a process which adjusts the response of the instrument. The calibration may also be checked ("bump-tested") periodically by the user, which does not adjust the instrument response. It is important to note that the description of the BHFS sensor operation in the supplemental information of [1] is incorrect, as they state that:

[A] portion of the sample is drawn from the manifold and directed to a combustibles sensor that measures the sample's methane concentration in the range of 0.05–100% gas by volume. The combustibles sensor consists of a catalytic oxidizer, designed to convert all sampled hydrocarbons to  $\rm CO_2$  and water. A thermal conductivity sensor is then used to determine  $\rm CO_2$  concentration.

However, the BHFS manual [4] clearly states that the catalytic oxidation sensor is used to measure concentrations from 0% to 5%  ${\rm CH_4}$  and the thermal conductivity sensor from 5% to 100%  ${\rm CH_4}$ . This is a critical distinction because understanding that the BHFS uses a different sensor for each range and that it must transition from the catalytic oxidation sensor to the thermal conductivity sensor in order to conduct accurate measurements is critical to understanding the problem of sensor transition failure.

I initially conducted field testing of the UT sampler in conjunction with the UT team at a NG production site with a wellhead gas CH<sub>4</sub> concentration of 90.8%. NG composition analysis (via gas chromatograph-flameionization detector) of wellhead gas at this site was conducted by the host company just prior to the sampler testing. The tests were conducted by metering known flow rates of NG into the BHFS inlets through a rotameter (King Instrument Company, Garden Grove, CA; 0–10 scfm air

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scale). The sample concentration indicated by the internal BHFS sensor was recorded and compared to an external gas concentration monitor used to measure the actual NG concentration at the sampler exhaust (Bascom-Turner Gas Sentry CGA 201, Norwood, MA). The Gas Sentry unit was calibrated with 2.5% and 100%  ${\rm CH_4}$  prior to the testing; exhaust concentrations measured using this unit agreed with concentrations calculated using the sampler flow rate and amount of NG metered into the inlet to within an average of  $\pm 6\%$ .

This field testing was conducted in March of 2014 and is described by [10]; the UT sampler is identified therein as BHFS No. 3. At the time of this testing, the UT BHFS had firmwareVersion 3.04 (September 2013); this sampler had been calibrated 2 weeks prior to the fieldtest and had been used for emission measurements at production sites since that time. The response of the sensors was checked ("bump-tested") by the UT field team but not calibrated prior to the start of testing. This was apparently consistent with the UT fieldprogram methodology: the sampler had been used for measurements with only sensor bump tests, but without the actual calibration unless the sensors failed the bump tests (as was acceptable according to the manufacturer's guidelines) during their ongoing field measurement program and was provided to me for these measurements "ready for testing".

Although the UT sampler's internal sensors initially measured the sample concentration correctly, after ~20 min of testing the sampler's sensors failed to transition from the catalytic oxidation scale (<5% NG) to the thermal conductivity scale (>5% NG), resulting in sample concentration measurements that were 11-57 times lower than the actual sample concentration (Fig. 5). Because sample concentration is directly used to calculate emission measurements made by the sampler, this would result in emission measurements that are too low. After this sensor transition failure occurred, the UT BHFS was calibrated (not simply "bump-tested") and thereafter did not exhibit any further sensor transition failures even during a second day of testing at sites with wellhead CH<sub>4</sub> concentrations as low as 77%. Two other BHFS that were not part of the UT program were also tested using the same procedure: these instruments had the most updated firmware commercially available (Version 3.03) and were put through an actual calibration sequence by the instrument distributor's representative prior to any testing. Neither of these instruments exhibited sensor transition failure at any of the sites. These results combined with the sensor transition failure previously observed in instruments with earlier versions of firmware suggest that the combination of updated firmware and frequent actual calibrations might reduce sensor failure, although this has not been proved conclusively [10, 11].

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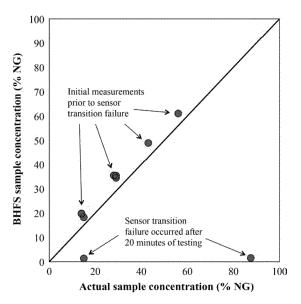


Figure 5. Performance of the BHFS used during the [1] study with NG composed of 90.8% CH<sub>4</sub>; instrument firmware had been upgraded to version 3.04 after that study but before this testing; calibration was 2 weeks old. Sensor transition failure set in after ~20min of testing; this failure was eliminated once the BHFS was put through a calibration sequence (as opposed to just a response test). BHFS, Bacharach HiFlow Sampler: NG, natural gas.

The UT recently published a follow-up study of pneumatic device emissions [2]. As part of this work, Allen et al. [2] conducted laboratory testing of the UT BHFS by making controlled releases of both 100% CH<sub>4</sub> and a test gas of 70.5% CH<sub>4</sub> mixed with heavier hydrocarbons into the UT BHFS and did not report any sensor transition failures during these tests, but during this laboratory testing the sampler (with the updated firmware version 3.04) was calibrated (not 'bump-tested") immediately prior to any testing. Consequently, the absence of sensor failure during their laboratory testing is consistent with the results observed during the March 2014 field tests, where calibrating the instrument eliminated the sensor failure.

Allen et al. [3] have suggested that the protocol during their field campaign was to check the calibration of the UT BHFS anytime it was turned on and that not following this protocol led to the sensor transition failure observed during this testing. However, in this instance, the sensor failure occurred both prior to and after the instrument was restarted. Additionally, the UT team observing the testing process did not suggest a calibration check when the instrument was turned back on for further testing. It was only after the sensor failure was observed that they checked and calibrated the instrument, so it

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does not appear that their protocol was to check the instrument calibration anytime it was turned on.

In summary, because the firmwarefor the UT sampler was updated prior to this testing (and therefore not the same as the version used during the UT field campaign [1]), and updated firmware may be a factor in reducing sensor failure, it is not expected that these test results are representative of how frequently sensor transition failure might have occurred during the UT study [1]. However, these results do clearly demonstrate that sensor transition failure could occur while using the UT BHFS.

## Comparison With Other Pneumatic Device Studies

Two other recent studies have measured emission rates from pneumatic devices by installing meters into the supply gas lines of the devices, as opposed to measuring emissions using the BHFS as was done by Allen et al. [1]. Prasino [22] used the meter installation technique to study emissions from pneumatic controllers in British Columbia, and the UT follow-up study [2] installed meters to measure emission rates from pneumatics in the four regions surveyed in the previous UT study [1].

Unfortunately, it is not possible to compare the pneumatic device emission factors from [1] to those from either the Prasino study, or from [2], because even though [1] sought to randomly sample pneumatic devices, the result was clearly an emitter data set (measurements focused on pneumatic devices that were emitting), while the Prasino data set was made with a random selection of devices and [2] made comprehensive measurements of all devices that could be measured safely at each site. This difference can be demonstrated by comparing the percentage of emitting intermittent pneumatic devices occurring in [1] to that in [2]. In [1], 95.3% (123 out of 129 intermittent devices) were greater than zero, with the smallest nonzero emitter equal to 0.12 scfh  $(0.0034 \text{ m}^3 \text{ h}^{-1})$ . In [2], only 57.5% (184 out of 320) intermittent devices) were greater than zero. This percentage of nonzero measurements drops further if the lowest nonzero emitter (0.12 scfh; 0.0034 m<sup>3</sup> h<sup>-1</sup>) observed by [1] is used as a threshold, in which case only 21.3% (68 out of 320) would be considered emitters. Since this threshold of 0.12 scfh (0.0034 m<sup>3</sup> h<sup>-1</sup>) is 25 times lower than the typical minimum range of the Fox FT2A meters by [2], the reported emitters below this threshold are most likely instrument noise caused by the meter's thermal elements inducing convection currents [7].

Consequently, although the intent of [1] was to survey randomly selected devices, their approach actually resulted in a data set comprised almost exclusively of emitting devices; this possibility is acknowledged by [2]. Therefore,

average emissions and emission factors for pneumatic devices calculated from [1] cannot be compared to those calculated from data collected by random or comprehensive sampling, such as presented in [22] or [2], because the emitter data set removes almost all the zero emitters and would result in much higher average emissions.

However, both [1] and [2] provide the  $\mathrm{CH_4}$  composition of the wellhead gas at the sites surveyed. This allows a comparison of emission rate patterns as a function of  $\mathrm{CH_4}$  concentration between devices measured by the BHFS [1] and by installed meters [2]. If the scarcity of high emitters measured by BHFS at sites with lower  $\mathrm{CH_4}$  concentrations in the initial UT study [1] was not an artifact caused by sensor transition failure, then the same concentration pattern should be present whether measured by the BHFS or by installed meters.

For this analysis, I removed the Rocky Mountain region to eliminate any bias from current or impending regulations that might have affected emission rates. Additionally, I focused on emissions from intermittent pneumatics because that provides the most complete data set from the two studies. Finally, as noted previously, the pneumatic device measurements from [1] apparently focused on emitting devices, whereas the devices surveyed in [2] were sampled as comprehensively as possible so the occurrences of high emitters in each study cannot be directly compared. Consequently, it is the ratio of the occurrences of high emitters at low CH<sub>4</sub> sites compared to high CH<sub>4</sub> sites within each study that must be compared.

As seen in Table 1, when measured by [1] via BHFS, the occurrence of emitters >0.4 scfm (0.7 m³ h $^{-1}$ ) (on a percentage basis) at sites with wellhead gas compositions <91% CH $_4$  is almost a factor of five less than at sites with CH $_4$  >91%, consistent with BHFS sensor failure. Conversely, when measured via installed meters [2], the occurrence of emitters >0.4 scfm (0.7 m³ h $^{-1}$ ) at sites with wellhead gas compositions <91% CH $_4$  is almost a factor of three higher than at sites with >91% CH $_4$ , indicating a complete reversal in this trend. This stark difference between BHFS measurements and installed meter measurements corroborates that the scarcity of high emitters at sites with lower wellhead gas CH $_4$  content present in [1] was an artifact due to sensor failure in the BHFS.

# Focused Analysis of the UT Study Equipment Leaks

In order to better understand the threshold of wellhead gas CH<sub>4</sub> concentrations at which sensor transition failure might occur, I conducted further analysis focused only on the equipment leak measurements in [1]. Equipment leaks were targeted because they are expected to be short term, steady state measurements, whereas emissions

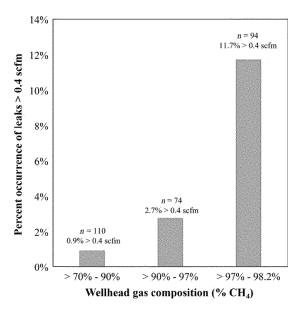
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Table 1. Occurrence of intermittent pneumatic device high emitters as a function of wellhead gas composition, measured by Bacharach Hi- Flow Sampler (BHFS) and installed meters (Rocky Mountain region excluded).

	No. of devices measured	No. of devices with emissions >0.4 scfm	% of devices with emissions >0.4 scfm
Allen et al. [1] (Measured by BHFS sampler)			
Wellhead gas composition >91% CH₄	85	28	32.9
Wellhead gas composition <91% CH₄	44	3	6.8
Ratio of frequency of high emitters at sites with welll wellhead gas compositions >91 $\%$ CH $_{\!4}$	nead gas compositions <91% Ch	ન્ to sites with	0.21
Allen et al. [2] (Measured by installed meters)			
Wellhead gas composition >91% CH₄	106	3	2.8
Wellhead gas composition <91% CH <sub>4</sub>	97	8	8.2
Ratio of frequency of high emitters at sites with welll wellhead gas compositions >91% CH <sub>4</sub>	nead gas compositions <91% Ch	ન <sub>4</sub> to sites with	2.9

reported from pneumatic devices and chemical injection pumps are likely to be an average of several measurements, and emissions from tanks may have an NG composition different from the reported wellhead composition.

Figure 6 presents the occurrence of equipment leaks in [1] that are >0.4 scfm (0.7 m³ h $^{-1}$ ) as a function of site CH $_4$  concentrations. At sites with gas compositions of >97% CH $_4$ , 11.7% of the leaks were >0.4 scfm (0.7 m³ h $^{-1}$ ). At sites with wellhead compositions between 90% and 97% CH $_4$ , only 2.7% of the leaks were >0.4 scfm



**Figure 6.** Occurrence of equipment leaks >0.4scfm as a function of site well head gas CH <sub>4</sub> content in the [1] study. Leaks >0.4 scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of &cfm. The large increase in the occurrence of leaks >0.4 scfm at sites with CH<sub>4</sub> content >97% indicates sensor transition failure below that threshold.

(0.7 m³ h⁻¹), and this occurrence dropped to less than 1% at sites with wellhead gas compositions of <90% CH₄, indicating that the sampler's ability to measure leaks >0.4 scfm (0.7 m³ h⁻¹) declined dramatically with decreasing concentrations of CH₄ in the wellhead gas (Fig. 6). This analysis indicates the BHFS may underreport emitters >0.4 scfm (0.7 m³ h⁻¹) even when making measurements of NG streams with CH₄ content up to 97%, and provides a valuable refinement of the possible CH  $_4$  concentration threshold where sensor failure may occur, since the highest CH₄ wellhead content available for direct field testing of the BHFS was only 91.8%.

#### Comparison of the UT Study Downwind Tracer Ratio Measurements to On-Site Measurements

Allen et al. [1] also made emission measurements using a downwind tracer ratio method at 19 sites for comparison to their on-site measurements. Their emissions from onsite measurements were calculated by using direct measurements of equipment leaks and pneumatic devices that were made by the UT team combined with estimates of emissions from any sources at the well pad that were not measured. These unmeasured sources included all tanks and compressors (compressors were a small source in comparison to all other sources) as well as any pneumatics that was not directly measured during the site survey. For CH<sub>4</sub> emissions from tanks and compressors, the authors used "standard emissions estimation methods" [1]. For pneumatic devices that were not surveyed, they applied their own emission factors based on the measurements of pneumatic devices collected during the UT study.

The tracer ratio measurements were made by releasing a tracer gas at a known rate to simulate the emissions from the site being measured. Simultaneous downwind measurements were then made of the concentrations of both the tracer gas and  $CH_4$ , and then the emission rate

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of  ${\rm CH_4}$  was calculated after correcting for background  ${\rm CH_4}$  and tracer concentrations. The tracer ratio method allows for the calculation of  ${\rm CH_4}$  emissions from the entire production site by accounting for the dilution of  ${\rm CH_4}$  as it is transported into the atmosphere from the source to the receptor.

In summarizing their tracer ratio measurements, [1] state: "For the production sites, emissions estimated based on the downwind measurements were also comparable to total on-site measurements; however, because the total on-site emissions were determined by using a combination of measurements and estimation methods, it is difficult to use downwind measurements to confirm the direct source measurements." However, upon further examination, I found that the downwind tracer measurements do in fact indicate the occurrence of sensor transition failure in their BHFS measurements.

Table 2 summarizes the characteristics of the sites surveyed by [1] using both the BHFS and the tracer ratio method. As described above, the on-site total is a combination of the measurements made by BHFS and estimates for any sources not actually measured by the UT team. I calculated the ratio of actual BHFS measurements to

the total reported on-site emissions (estimated and measured) using the supplemental information provided by [1]. Actual measured emissions ranged from 1% to 79% of the total reported on-site emissions and the on-site total emissions range from 13% to 3500% of the downwind tracer ratio measurements (Table 2).

Table 3 compares the tracer ratio measurements to the on-site emissions, categorized by  ${\rm CH_4}$  content in the well-head gas and by the fraction of actual BHFS measurements that comprise the on-site emissions. As shown in Table 3, when comparing all sites without separating them into these categories, the total of the tracer ratio measurements does agree closely to the on-site emissions, as [1] concluded. However, four of the sites had wellhead gas compositions of  $\geq$ 97%  ${\rm CH_4}$ , at which the BHFS would be expected to make accurate measurements. The remaining 15 sites had wellhead gas compositions of <82%  ${\rm CH_4}$ , at which sensor transition failure might occur and the BHFS would underreport emissions measurements.

Once the sites are categorized by these wellhead gas compositions, a deficit between the on-site emissions and the tracer ratio measurements appears in sites with lower  $CH_A$  concentrations, and this deficit becomes more

Table 2. Sites surveyed by Allen et al. [1] using both Bacharach Hi-Flow Sampler (BHFS) and downwind tracer methods.

Tracer site name <sup>1</sup>	BHFS site name <sup>1</sup>	Wellhead gas CH <sub>4</sub> concentration (%)	On-site total <sup>2</sup> (BHFS measurements and estimates) (scfm CH <sub>4</sub> )	BHFS measure- ments/on-site total <sup>3</sup>	Leaks measured by BHFS/on-site total <sup>3</sup>	Tracer ratio emission rate (scfm CH <sub>4</sub> )	On-site total/ tracer ratio emission rate
MC-1	MC-1	70.9	1.89	0.12	0.12	2.32	0.815
MC-2	MC-14	78.1	0.99	0.34	0.01	2.00	0.495
MC-3	MC-20	77.2	1.63	0.45	0.18	2.95	0.552
MC-4	MC-5	74.2	2.31	0.19	0.14	3.36	0.687
MC-5	MC-16	79.3	1.85	0.56	0.18	4.16	0.445
RM-1	RM-7	81.9	0.22	0.11	0.09	0.584	0.368
RM-2	RM-8	74.5	4.43	0.02	0.02	1.70	2.60
RM-3	RM-1	76.4	0.13	0.67	0.69	0.442	0.303
RM-4	RM-3	74.9	0.11	0.21	0.00	0.839	0.137
RM-5	RM-2	74.5	0.09	0.35	0.33	0.240	0.392
RM-6	RM-5	74.5	0.74	0.41	0.42	0.421	1.75
RM-7	RM-14	74.5	0.27	0.26	0.26	0.368	0.736
RM-8	RM-19	76.2	0.29	0.82	0.79	1.08	0.266
RM-9	RM-12	74.5	0.38	0.05	0.05	0.864	0.436
RM-10	RM-4	76.2	2.86	0.01	0.00	0.080	35.7
AP-2	AP-23	97.6	1.28	0.68	0.35	0.270	4.74
AP-3	AP-43	97.0	4.75	0.62	0.59	4.12	1.15
AP-4	AP-37	97.0	1.36	0.44	0.42	0.709	1.92
AP-5	AP-18	97.0	0.39	0.74	0.69	0.288	1.37

<sup>&</sup>lt;sup>1</sup>MC, Midcontinent; RM, Rocky Mountain; AP, Appalachia. Different site numbers were used to identify the same sites in the [1] supplemental information depending on whether BHFS or tracer ratio measurements were under discussion.

<sup>&</sup>lt;sup>2</sup>On-site totals were calculated by [1] by combining measurements made by the BHFS with estimates of any sources not measured; these estimates were made using mathematical models for tanks as well as emission factors for compressors and any pneumatic controllers not directly measured. <sup>3</sup>Calculated by this author from [1] supplemental information.

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pronounced as the amount of the on-site emissions actually measured by the BHFS becomes a larger fraction of the total on-site emissions (measured and estimated). As seen in Table 3, for the high CH<sub>4</sub> sites where the sampler should function properly, the on-site measurements and estimates exceed the tracer measurements, but approach a ratio of one (complete agreement) as the amount of actual measurements increases. For the two sites with wellhead gas compositions ≥97% where the measured equipment leaks (which should produce steady emissions as compared to pneumatic devices which might be intermittent) averaged 64% of the total on-site measurements and estimates, the on-site total still exceeds the tracer measurements but are within 17% (Table 3). However, for the sites with wellhead gas  ${\rm CH_4}$  concentrations <82%, there is a clear trend of increasing deficit of the on-site emissions compared to the tracer ratio measurements as the actual BHFS measurements become a larger part of the on-site total. For instance, for the nine sites with at least 20% of on-site emissions from BHFS measurements (for an average of 45% of the total on-site emissions measured by the BHFS), the on-site emissions are only 49% of the tracer measurements (Table 3). For the two sites that had greater than 67% of on-site emissions data actually measured by the BHFS (for an average of 75% of on-site emissions data measured by the BHFS), the on-site emissions are only 28% of the tracer measurements (Table 3).

Comparing the on-site data to the downwind tracer measurements provides two valuable insights. First, there were six sites in the Rocky Mountain region for which at least 20% of the on-site emissions were measured by the BHFS (for an average of 45% actual BHFS measurements) (Table 2). For these six sites, the on-site emissions average 48% of the tracer data. For the two sites in this

region with at least 67% of on-site emissions from actual BHFS measurements (and with BHFS measurements averaging 75% of the total on-site data), the on-site emissions were only 28% of the tracer measurements (Table 2). This provides clear evidence that the sampler actually did fail in the Rocky Mountain region, as opposed to any possible regional differences (discussed previously) that might have created an emission pattern of no high emitters at sites with lower  ${\rm CH_4}$  concentrations in the wellhead gas.

Additionally, the tracer measurements provide a method to estimate the magnitude of errors introduced in the data collected by [1] due to BHFS sensor transition failure. For all of the sites with wellhead gas compositions ≥97% CH<sub>4</sub> (where the sampler should operate correctly), the emission rates determined by on-site measurements exceeded those determined by the downwind tracer ratio measurements. Assuming that the tracer method accurately measured the total emissions from the sites surveyed (e.g., [8, 15, 16]), I concluded that the methods used in [1] overestimated the on-site sources that were not directly measured. Therefore, I calculated the error in BHFS measurements at sites with low CH<sub>4</sub> wellhead gas composition by assuming the tracer ratio measurements are correct. I have also assumed for this analysis that the estimates of any onsite sources made by [1] are also correct, even though the tracer data indicate they may be too high, because this is conservative in the sense that correcting for this overestimate would increase the BHFS error calculated below. Given these assumptions, subtracting the on-site estimated emissions from the tracer ratio emissions gives the expected measurement total that should have been reported from the BHFS measurements. Comparing this expected measurement total to the actual

Table 3. Comparison of on-site measurements to tracer ratio measurements made by Allen et al. [1] categorized by wellhead gas CH<sub>4</sub> concentration.

Site category (number of sites in parentheses)	Average percentage of on-site emissions reported by BHFS	Total on-site emissions (reported by BHFS and estimated) (scfm CH <sub>4</sub> )	Total emissions measured by tracer (scfm CH <sub>4</sub> )	Ratio of on-site emissions to emissions measured by tracer
All sites (19)	37	26.0	26.8	0.97
Sites where BHFS measurements are expected	to be accurate (wellhead	gas composition ≥97% CH	<u>k</u> )	
All sites (4)	62	7.78	5.39	1.44
Sites with >50% BHFS measurements (3)	68	6.42	4.68	1.37
Sites with >50% equipment leaks (2)	64 (equipment leaks/on-site total)	5.14	4.41	1.17
Sites where BHFS measurements are expected	to underreport high emi	tters (wellhead gas composi	tion <82% CH <sub>4</sub> )	
All sites (15)	28	18.2	21.4	0.85
Sites with ≥5% BHFS measurements (13)	35	10.9	19.6	0.56
Sites with ≥20% BHFS measurements (9)	45	6.10	12.5	0.49
Sites with >50% BHFS measurements (3)	69	2.27	5.68	0.40
Sites with >67 % BHFS measurements (2)	75	0.42	1.52	0.28

BHFS, Bacharach Hi-Flow Sampler.

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measurement total reported by the BHFS provides an estimate of the error in BHFS measurements made by Allen et al. [1].

Table 4 presents the results of this analysis, and shows that for the 13 sites with wellhead gas compositions <82% CH<sub>4</sub> and with at least 5% actual BHFS measurements (with an average of 35% of emission sources measured by BHFS; bottom half of Table 3), the actual measurement total of the BHFS is less than one-third of the expected total, and this appears consistent as sites with greater fractions of actual BHFS measurements are examined. For these sites, the emission rates for equipment leaks and pneumatics devices presented by [1] are approximately equal, so it is not possible to assign a larger error to one category or another. Additionally, the errors introduced by the sensor failure would be expected to vary from site to site depending on how many emitters were present with emission rates exceeding the sensor transition threshold ceiling. Nevertheless, for these 13 sites, the BHFS underreported emissions for equipment leaks and pneumatic devices on average by more than a factor of 3 (Table 4).

Although the magnitude of error due to BHFS sensor failure is not known for all the sites in [1], the tracer ratio measurements make clear that the BHFS measurements for sites with lower CH<sub>4</sub> content in the wellhead gas could be at least a factor of three too low. More precise estimates of errors in [1] are not possible because of the nature of the sensor failure. Unlike a simple calibration error, for which it might be possible to correct, when sensor transition failure occurs, it is not possible to know for any particular measurement if the failure has occurred, and if it has, what the resulting error was, since the reported emission rates could range from 20% to two orders of magnitude too low.

#### **Implications**

Sensor transition failure is clearly apparent in the BHFS measurements made in the UT study by Allen et al. [1], as evidenced by the rare occurrence of high emitters at sites with lower CH<sub>4</sub> (<91%) content in the wellhead gas. The occurrence of this sensor transition failure was corroborated by fieldtests of the UT BHFS during which it exhibited this sensor failure, as well as by tracer ratio measurements made by [1] at a subset of sites with lower wellhead gas CH4 concentrations. At this subset of sites, the tracer ratio measurements indicate that the BHFS measurements were too low by at least a factor of three. Because BHFS measurements were the basis of 98% of the inventory developed by [1] using their own measurements (and 41% of their total compiled inventory), the inventory clearly underestimates CH<sub>4</sub> emissions from production sites. However, the extent of this error is difficult to estimate because the underreporting of emission rates due to BHFS sensor transition failure at any given site would vary depending on sampler performance and on how many high emitters were present at that site. Estimating this error is further complicated by the fact that the data set collected for pneumatic devices by [1] was an emitter data set; this might offset the effect of underreported high emitters in their pneumatic device emission factors. Finally, although real differences may exist in regional emission rates, the UT data set [1] should not be used to characterize them because the occurrence of sensor failure clearly varied between regions due to variations in wellhead CH₄ compositions, which may mask any actual regional differences that existed.

Although the performance of the BHFS may vary between instruments or with sensor age or calibration vintage, this analysis of the [1] data set shows that measurements made using a BHFS for NG streams with  $\mathrm{CH_4}$  content

**Table 4.** Estimation of underreporting in Allen et al. [1] BHFS measurements of CH<sub>4</sub> emission rates at sites with low CH<sub>4</sub> well head gas composition (<82%), using downwind tracer measurements (from Table 3).

Minimum percentage of on-site emissions reported by BHFS	Average percentage of on-site emissions reported by BHFS	No. of sites	Total emissions measured by tracer (scfm CH <sub>4</sub> )	On-site emissions estimated by UT (excludes BHFS measure- ments) (scfm CH <sub>4</sub> )	Expected BHFS measurement total (tracer – on-site estimates) (scfm CH <sub>4</sub> )	Emissions reported by BHFS (scfm CH <sub>4</sub> )	Ratio of reported BHFS to expected BHFS
<u></u>	35	13	19.63	7.09	12.54	3.81	0.30
≥20	45	9	12.50	3.34	9.16	2.76	0.30
>50	69	3	5.68	0.71	4.97	1.56	0.31
>67	75	2	1.52	0.11	1.42	0.31	0.22

BHFS, Bacharach Hi-Flow Sampler; UT, University of Texas.

UT Study Underestimates Methane Emissions

up to 97% could lead to severe underreporting of NG leaks. That this failure can occur at such high  $\mathrm{CH_4}$  concentrations, which are close to the higher end of those found in transmission and distribution systems, indicates that past measurements in all segments of the NG supply chain could have been affected by this problem. Because the BHFS sensor transition failure phenomenon is not fully understood, it is not known how much this error may have affected past measurements of  $\mathrm{CH_4}$  emission rates. Two factors preclude this: first, the performance of any individual BHFS may vary, and second, once sensor transition failure occurs, there is no way to determine the magnitude of the measurement error in the absence of an independent flux or concentration measurement.

If BHFS sensor transition failure has occurred during industry monitoring at transmission, storage, and processing compressor stations where the BHFS is approved for leak measurements mandated by the USEPA Subpart W Greenhouse Gas Reporting Program (GHGRP) [23], then these errors could be larger than those observed at production sites. Leaks at transmission, storage, and processing compressor stations commonly exceed 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) (the approximate threshold for BHFS sensor transition failure) and in some cases may range from 10 to over 100 scfm. Because the largest 10% of leaks typically account for 60-85% of the total leak rate at a given facility [9, 25], sensor transition failure in the BHFS could bias CH4 emission inventories compiled by the USEPA GHGRP substantially low since the most significant leaks could be underreported. Additionally, leak measurements using the BHFS may be used to guide repair decisions at NG facilities, and underreporting of leaks could compromise safety if large leaks remain unrepaired as a result.

Finally, it is important to note that the BHFS sensor failure in the UT study [1] went undetected in spite of the clear artifact that it created in the emission rate trend as a function of wellhead gas CH<sub>4</sub> content and even though the authors' own secondary measurements made by the downwind tracer ratio technique confirmed the BHFS sensor failure. That such an obvious problem could escape notice in this high profile, landmark study highlights the need for increased vigilance in all aspects of quality assurance for all CH<sub>4</sub> emission rate measurement programs.

#### Acknowledgments

The author thanks Dave Allen (University of Texas at Austin) for making the UT BHFS available for field testing, and Adam Pacsi (University of Texas at Austin), Matt Harrison and Dave Maxwell (URS Corporation), and Tom Ferrara (Conestoga Rovers & Associates) for their assistance

with the field testing of the BHFS. This paper was substantially improved by the comments of three anonymous reviewers.

#### **Conflict of Interest**

The author is the developer of high flowsampling technology (US Patent RE37, 403) and holds a license to use it for any purpose; however, he does not sell high flow samplers nor was he involved in the development of the Bacharach Hi-Flow Sampler.

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To: McKittrick, Alexis[McKittrick.Alexis@epa.gov]; DeFigueiredo,

Mark[DeFigueiredo.Mark@epa.gov]

Cc: Friedman, Kristina[Friedman.Kristina@epa.gov]; Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]

From: Weitz, Melissa

Mon 12/14/2015 9:47:29 PM Sent:

Subject: FW: Meeting with EPA re: Hi-Flow Sampler Issues

It's here....

He also just sent a new group email that I'll forward to this group.

#### Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process I can set up a time for our group to

speak with him for early-mid January.

Melissa

From: Touche Howard [mailto:touche.howard@indacoags.com]

Sent: Monday, December 14, 2015 3:35 PM To: Weitz, Melissa < Weitz. Melissa@epa.gov>

Subject: Meeting with EPA re: Hi-Flow Sampler Issues

Dear Ms. Weitz:

I just received Dr. Dunham's letter regarding meeting about the sensor failure in the Bacharach Hi-Flow Sampler. I appreciate the thought that she put into the letter, and I'll be happy to work around your schedule. I recognize that given the holiday season and other pressing issues that it's unlikely that you'll be available before January. However, I hope it will be as soon as possible because this is a pressing issue for lots of reasons, including the fact that companies can start making their 2016 Subpart W measurements as of January 1, and it would be better not to let another year of measurements be potentially affected by this problem.

Just FYI, I didn't receive Dr. Dunham's letter until after I had sent the email to Dave Allen asking him to participate in meeting with you. If I had, I would have held off and let you invite him. I need to respond to Matt Harrison's statement that there is no safety issue, but after that I'll wait to hear from you. I do think, however, that the best approach to understanding these issues is to involve Dave, his EDF science advisory panel, EDF scientists, and any interested members of

the EDF technical and steering committees. I believe that will allow all of the questions to be asked (and hopefully answered) immediately, and that gives you the best information as quickly as possible.

Please call me at 919 943 9406 if you have any questions.

Thanks,

Touche'

To: allen@che.utexas.edu[allen@che.utexas.edu] Cc: McKittrick, Alexis[McKittrick.Alexis@epa.gov]; terri shires@aecom.com[terri shires@aecom.com]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Gunning, Paul[Gunning.Paul@epa.gov]; McCabe, Janet[McCabe.Janet@epa.gov]; RAlvarez@edf.org[RAlvarez@edf.org]; shamburg@edf.org[shamburg@edf.org]; Fernandez, Roger[Fernandez.Roger@epa.gov]; rharriss@edf.org[rharriss@edf.org]; ritterk@api.org[ritterk@api.org]; dnelson@edf.org[dnelson@edf.org]; sedlak-office@est.acs.org[sedlak-office@est.acs.org]; dmccabe@catf.us[dmccabe@catf.us]; dlyon@edf.org[dlyon@edf.org]; Maxwell, Dave (Austin)[dave.maxwell@aecom.com]; dschroeder@catf.us[dschroeder@catf.us]; dzavala@edf.org[dzavala@edf.org]; Chuck Kolb[kolb@aerodyne.com]; Gamas, Julia[Gamas.Julia@epa.gov]; linda.lee@arb.ca.gov[linda.lee@arb.ca.gov]; bmordick@nrdc.org[bmordick@nrdc.org]; amrowka@arb.ca.gov[amrowka@arb.ca.gov]; casey.pickering@erg.com[casey.pickering@erg.com]; Wisetiawa@arb.ca.gov[Wisetiawa@arb.ca.gov]; Smith, James-D[Smith.James-D@epa.gov]; Snyder, Jennifer[Snyder.Jennifer@epa.gov]; michael.ege@tceq.texas.gov[michael.ege@tceq.texas.gov]; paige.sprague@tceq.texas.gov[paige.sprague@tceq.texas.gov]; adam.pacsi@chevron.com[adam.pacsi@chevron.com]; Jeff.Rees@pxd.com[Jeff.Rees@pxd.com]; matt.harrison@aecom.com[matt.harrison@aecom.com]; alr@andrew.cmu.edu[alr@andrew.cmu.edu]; awilcox@harcresearch.org[awilcox@harcresearch.org]; andres.restrepo@sierraclub.org[andres.restrepo@sierraclub.org]; gabrielle.petron@noaa.gov[gabrielle.petron@noaa.gov]; natalie.spiegel@sierraclub.org[natalie.spiegel@sierraclub.org]; nathan.matthews@sierraclub.org[nathan.matthews@sierraclub.org]; rsawyer@me.berkeley.edu[rsawyer@me.berkeley.edu]; Ganapathy, Roopa (EC/EC)[Roopa.Ganapathy@canada.ca]; vgowrishankar@nrdc.org[vgowrishankar@nrdc.org]; dan.hill@pe.tamu.edu[dan.hill@pe.tamu.edu]; Matthew.Fraser@asu.edu[Matthew.Fraser@asu.edu]; seinfeld@caltech.edu[seinfeld@caltech.edu]

From: Touche Howard

Sent: Mon 12/14/2015 9:42:18 PM

Subject: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

#### Dave --

I think that Matt's statement of "I see no safety issue" (regarding the Bacharach Hi-Flow sampler's problem of reporting leaks as far smaler than they actually are) might have resulted from your team either not being aware of all the potential uses of the Hi-Flow sampler or from having a somewhat narrow view of what problems can compromise safety.

Probably half of the leak measurement programs I've conducted were for private companies whose primary goals were to reduce gas loss and to improve safety, as opposed to cataloging greenhouse gas emissions. At 1 to 2% of all the facilities I've been to, we found leaks that caused the operators to immediately shut down equipment. Examples include leakage into compressor distance pieces that was large enough to cause back pressure into the engine crankcase, flanges that had a leak rate large enough that it might cause further gasket erosion and failure, and large leaks at welds on compressor fuel gas systems that might catastrophically fail or be large enough to reach an ignition source due to induced sparking at vibrating components in the ignition coil area.

Did we prevent explosions in those cases? We'll never know, but we did provide one layer of defense by eliminating imminently dangerous conditions. So if only 1% of facilities have a dangerous underlying condition that might go undiscovered if a Hi-Flow sampler fails, is it really worth an hour of your time to address this issue? I think most people would say yes.

Even high flow surveys that focus on research or greenhouse gas reporting have the opportunity to reduce dangerous conditions if done properly. I think the protocol in most (hopefully all) leak measurement programs, whatever their focus, is to immediately alert facility operators of any hazardous conditions found. So it's certainly not acceptable to leave hazards unidentified due to sampler failure just because many surveys are focused on greenhouse gas emissions instead of facility integrity.

Other instances where sampler failure might affect safety are when it is used to make an on the spot repair decision when a leak is discovered by an operator and when it is used to survey facilities being put into initial service. And as I pointed out previously, we don't know all the ways a sampler might be used now or in the future. If, for instance, it were used to rank distribution leaks for repair, under reporting large leaks could have tragic consequences.

Now you might think that other indications, such as an IR camera, or auditory, visual, and olfactory (AVO) detection would provide clues that a leak was much larger than the sampler indicated, but most people just don't have that level of experience, and a noisy and/or hot environment can make it even more difficult. There's an excellent example of this in your Phase II pneumatic work, where Device No. XQ01-PC04 was measured both by Hi-Flow (0.13 scfh) and meter (37.37 scfh), and you assume the Hi-Flow measurement is too low due to the device not being adequately enclosed. However, this device was a continuous bleed controller with a high emission rate (in the top 20% of the continuous controllers you measured). Consequently, even though the Hi-Flow was making an easy to read steady state measurement for most of that interval, your technicians did not recognize that the Hi-Flow reading was almost 300 times too low (if they had, they would have certainly attempted to correct the problem while the measurement was being made). This highlights that even people who had been making these type of measurements day after day during an extensive field program could not accurately judge emission rates without reliable instrumentation.

And although safety systems like gas detectors or hot work permits provide one line of defense, they can't always protect the facility from a leak that could have been fixed but wasn't, and then either failed catastrophically or found an ignition source before automatic detection shut down equipment. Having been to so many facilities, I've heard lots of stories of past explosions. My favorite was was told to me by an operator who was the son of a compressor station manager. When he was growing up, they lived near the station, and one night after dinner he wanted to go to the mechanic's shop at the site to work on his car. Oh, no, his mother says, it's your turn to do the dishes. So there he is, sulking at the sink, when the station blows up, basically right in front of him as he's watching out the kitchen window, and destroying with it the mechanic's shop where he would have been if his mother hadn't made him wash dishes.

Unfortunately, not all the stories had a happy ending like that.

I hope this provides a better perspective on the safety issues involved.

Thanks.

Touche'

On Wed, Dec 9, 2015 at 8:56 PM, Harrison, Matt <matt.harrison@aecom.com> wrote:

I see no safety issue. HiFlows are never used as safety devices to my knowledge

Matt Harrison 512-694-0572 Sent from my iPhone

On Dec 9, 2015, at 2:25 PM, "Touche Howard" <touche.howard@indacoaqs.com> wrote:

Dave --

Now that the EPA is considering using your initial EDF study at production sites (published in PNAS in 2013) and your follow-up study on pneumatic controllers (published in ES&T in 2014), it's critical that we resolve the Hi-Flow sensor failure and other quality assurance issues surrounding those studies as soon as possible. The quickest way to do that is for us to directly discuss these issues with EPA, and I think once you understand the evidence, you'll be able to see the problems immediately. To that end, let's try to get together tomorrow or Friday. (Melissa and Alexis - I can come up and meet with you either day, and if Dave can't make it, he can call in.)

My biggest concern is safety -- having an instrument that reports natural gas leaks far lower than they actually are is clearly a huge safety issue, and as long as you tell people that this problem didn't occur in your work, it will be very hard for anyone to take it seriously. Meanwhile, for you and EPA, this also represents important health and environmental concerns. And of course since you were chair of the EPA Science Advisory Board while you were conducting this research, and the Hi-Flow sampler is one of the methods approved by EPA to make measurements for their greenhouse gas reporting program under Subpart W, I'm sure you feel a special responsibility to address these issues as soon as possible.

I've attached my ESE paper outlining the problems in your initial 2013 production study as well as my letter and your response about the 2014 study. I've also attached a reply that I wrote in response to your commentary on my paper in ESE, because even though you withdrew that commentary after seeing my response, I think my response did clarify some of the issues.

Since we unfortunately haven't had an opportunity to discuss these issues directly, I'll summarize the evidence here and what I believe are your counterpoints, based on your reviews of my paper and the commentary you submitted. I also want to allay your

concerns, which you've stated to others, that I'm raising these issues because I want to sell my own samplers or services. I'm only wrapping up loose ends now, and after this I won't be working in this area any more.

The first issue is sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS), where it can fail to transition from the low range (0 to 5% gas) catalytic oxidation sensor to the high range (5 to 100% gas) thermal conductivity detector, which can cause the sampler to report large leaks as being much smaller that they are. We don't know why this happens, but there's no question that it can, because we demonstrated it in three different instruments, including yours. It doesn't seem to occur for pure methane streams, but we've seen it in the field for gas streams with methane content as high as 91% (J. Air Waste Manag. Assoc. 65:856–862. doi: 10.1080/10962247.2015.1025925).

The effect of this problem is clear in your Phase I data, which I've plotted below showing emission rate as a function of site methane composition. As you can see, most of the high emitters only show up at sites with high methane compositions, and there's no reason that should happen in the real world, especially when you consider that it occurs for several different types of sources.

<image.png>G

Now I believe your counter argument is that this phenomenon is due to air pollution control regulations reducing emissions in the Rocky Mountain region, where the methane content of the gas is lower as well. However, several things tell us that's not the cause of the trend in the figure above. First, even when you take the Rocky Mountain region out of the analysis, there's still far more high emitters at sites with higher methane content. Second, even within just the Appalachia region, the occurrence of high emitters increases dramatically over a very narrow range of site methane compositions, from 95% to 98% methane (shown below). What that tells us is that sampler can start seeing some of the high emitters once methane composition is in the range of 95%, but is still missing a lot of them until methane composition gets up to the 97 to 98% range. This is also an extremely important indicator that this problem could be occurring even for gas streams with methane content above 95%, meaning the problem could occur in all segments of the natural gas industry.

<image.png>

Finally, your emissions measurements made by tracer technique confirm that sensor failure occurred and that the trend of emission rate vs concentration is not caused by regional differences. Now, in your comment you said you found my analysis of your tracer data complex, probably because I showed how Hi-Flow measurements got lower and lower than the tracer measurements for sites with fewer estimated emissions from

sources like tanks. So I've simplified that analysis, and just removed the two sites that had 98% or more of the emissions estimated as opposed to measured. This comparison of the tracer versus on site Hi-Flow measurements is shown below.

#### <image.png>

So clearly, as you've suggested, there are regional differences, assuming these sites are representative. The tracer data shows that the emissions from sites in the Rocky Mountain (RM) region are lower than the sites in the Mid-continent (MC) region, although in the same range as 75% of the Appalachia (AP) sites. But just as clearly, the sites with lower methane content (Rocky Mountain and Mid-continent, where sensor failure might occur consistently) have far lower (about a factor of two) Hi-Flow measurements than the tracer technique. Meanwhile, the sites with high methane content (Appalachia, where the problem isn't expected to occur) have Hi-Flow measurements close to or exceeding the tracer measurements. Keep in mind that because some of the on-site data comes from estimates, this masks the magnitude of the error, but at least this is a simple comparison.

Now if the variations between the tracer and the Hi-Flow were due to random experimental errors, then we'd expect roughly 50% of the sites to have tracer greater than Hi-Flow, and 50% lower. It's actually a 70/30 split, but the remarkable thing is that we can predict which region will have tracer greater than Hi-Flow and which won't. This is pretty much the same thing as me being able to walk into a bar and betting the barmaid that if I stand on her side of the bar and flip a coin it will always come up heads, but if I stand on my side of the bar and flip a coin, it will always come up tails. And in between drinks, we run that experiment, and it turns out that I'm right 16 out of 17 times.

Now that's a bar bet I'd like to be able to make routinely.

You also said in your unpublished comment to ESE that the testing I conducted on your instrument and others in March of 2013 showed a low occurrence of this problem. That's true of course, but I was surprised you said that, since you know that immediately after we did that testing that I met with some very experienced Hi-Flow technicians who specifically told me that they had fixed some of their samplers that had been reporting leaks too low by upgrading the sampler's software. Since all of the samplers we tested when we tested yours had new generation software, the only real surprise is that we saw any failure at all, and that failure was in your sampler. So even though new software improves the problem, it doesn't fix it completely. Additionally, there are lots of these samplers around the US and the world using older software, and lots of data that has been collected using samplers prior to software upgrades.

One other argument you made was that your Phase I pneumatic data, made by Hi-Flow, was higher than your Phase II pneumatic data, collected by meter, and if your Hi-Flow had been reporting too low, this should have been the other way around. The reason this isn't true is that your Phase I pneumatic data is clearly an emitter data set

(95% of them are emitting) while your Phase II data set is a comprehensive data set (about 21% are actual emitters). So you accidentally excluded sampling zero emitters in Phase I, which biases that data high by a factor of four to five, and offsets any Hi-Flow sensor failure. Additionally, the Phase II data actually shows exactly what I predicted to you it would show -- that the high emitters are more predominant at sites with lower methane compositions when measured by the inline meter as opposed to your Phase I measurements, where the sensor failure caused the high emitters at those sites to be under reported.

In any case, I think this shows that it probably would have been better to involve me directly in discussions you had with the EDF committees and others about this problem after I brought it to you in October of 2013, because I could have explained immediately why the reasons you thought this problem didn't affect your Phase I data were incorrect. It has been puzzling to me that given the overwhelming evidence, that this problem wasn't obvious to you, but I'm wondering if that might be due to inexperience with field measurements. As an example, in both your Phase I and Phase II papers, you incorrectly describe the operation of the Hi-Flow sensors, and without understanding that the Hi-Flow has to to switch back and forth between sensors to make accurate measurements, it's probably impossible for you to understand the sensor transition problem.

I'm wondering if inexperience might have also led to the problems in your Phase II work as well. It's a harsh environment for meters to be transported between field sites on rough roads and have raw natural gas run through them, and I think most people with experience in field measurements would have built in a routine testing of those meters during the project, rather than just check them before and after the project as you did. When you're out in the field looking at pneumatics, you see lots of them with oil or other hydrocarbon accumulations, so it's easy to picture how the meter sensor could get fouled, as yours did. I would think at least a weekly multi-point meter calibration and a daily single point flow check would be required to ensure accurate measurements. which is what was done during the EDF WSU distribution work. The Indaco Hi-Flows that were used in that project have a very similar flow measurement system to your Fox meter, which is a thermal element in a tube, and even though the distribution study was a much less harsh environment, where leaks of relatively clean distribution gas were measured and the flow system dilutes those leaks with air before the gas hits the sensors, full scale weekly calibrations and single point daily flow checks were conducted.

Now, as you remember, while that project was ongoing, I found that one of your two primary meters was measuring too low by a factor of three. Well, that's not a surprise, given the harsh environment. I haven't used the particular meter that you were using before, but I did look at the manual for it, and it clearly states that a dirty sensor will cause measurements to be too low.

But I think how you addressed that issue indicates further inexperience. Since you don't mention the meter test I made showing it was a factor of three too low in your

paper, but only indicate that you found the problem post project, it appears that you just kept using the meter, without trying to figure out what was wrong with it, and without instituting any additional meter checks.

Instead, it wasn't until the end of the project that you did any further checks, and at that point the response of the meter had changed again, to being low by about 34%. In order to understand more about the problem, you tried to use your Hi-Flow data to validate the meter results. Now your laboratory comparisons of the two for the most part are excellent and agree within 10%. But surprisingly, your field comparisons of the Hi-Flow to the meters are far worse. For measurements where either one or the other was >0.5 scfh, only 4 out of 19 (21%) are within 25%, and even for measurements >6 scfh, only 3 out of 10 (30%) are within 25% of each other. You do allude to the possibility of leaks affecting the measurements but don't give any indication that you tried to quantify the leaks that you think affected the measurements.

For comparison, in the WSU distribution work, where direct and tracer measurements were compared, 10 out of 14 (71%) were within 50% of each other, over a range of about 0.6 to 56 scfh. Now I would have liked that to be better, but I think I understand some of the challenges, one being that some of those that are far off are at really low emission rates, so missing just one source could throw you off a lot. But keep in mind, that's measuring the whole M&R facility or an underground leak, and comparing it to a downwind tracer flux measurement, so you have lots of challenges including multiple measurements at the facility and tracer source configurations.

But for your pneumatic work, while doing a direct comparison of Hi-Flow to meters, for just single sources, only 7 of 19 (37%) were within 50% of each other over a similar emission range of 0.5 to 60 scfh.

So unfortunately your comparison of High Flow to meters should not have been used to justify correcting your meter, especially when my direct test of that meter's performance mid-project showed it was much worse than the post project check indicated.

Another indication of the meter uncertainty came from Matt Harrison, who was present when I found that your meter was reading a factor of three too low, and said at the time, "Yeah, everyone knows that meter is flaky. You can hook it up to an pneumatic and hear the pneumatic fire but not see anything on the meter."

Now, along with the sensor getting dirty, your meter measurements might have been affected by two other factors mentioned in the meter manual. These meters are supposed to be oriented upright, and you need a certain length of straight run (I think for the meter you were using, six inches) before the meter. However, it appears, looking at a slide from the presentation about the project on your website shown below, that those conditions weren't met either. Although you can see in the close up that the meter is marked with a label that says "Keep Upright and Level", that

condition hasn't been met in either configuration pictured. Additionally, the entrance length doesn't appear to meet the required distance either.

<Upside Down Meter 1.jpg>

<Upside Down Meter Close-up.jpg>

I think these issues were all compounded by perhaps your lack of experience with what information editors and reviewers need to evaluate field measurement papers. Your meter problem is only mentioned in a footnote on page 59 of your Supplementary Information, and was likely missed by the editor and reviewers. But if reviewers with substantial field experience understood the entire picture -- that you only checked your calibration before and after the project, that there was an undisclosed mid project test showing meter performance was much worse than the correction you applied, that after you were shown one meter was faulty in the middle of the project that you simply continued to use it without finding out what was wrong or instituting improved calibration checks, "that everyone knew that meter was flaky," and that your Hi-Flow and meter field measurements don't compare very well -- I believe they would conclude that you didn't meet the fundamentals of quality assurance and that the paper would have been rejected.

So unfortunately neither the Phase I or Phase II data should be used by EPA. Although there may be large uncertainties in inventories, we shouldn't include numbers that have such large question marks. Think about cancer treatments. Those have very uncertain outcomes, but that doesn't mean that we don't want good quality assurance in cancer research or in the dosages of drugs or radiation therapy that are used. And when you consider the broad environmental impact of air toxics to the communities surrounding oil and gas facilities as well as the consequences of climate change, it's critical that we use the best data possible.

And as I said at the start, safety is my biggest concern regarding the HiFlow sensor failure, and I think perhaps again inexperience has caused you not to fully appreciate what a critical safety issue this is. I've spent a lot of time measuring leak rates at natural gas facilities, and I've seen facility personnel shut down units in order to address large leaks that we found due to safety concerns -- I've done lots of leak measurement programs that were focused more on the integrity of the facility rather than the issue of greenhouse gases. Additionally, we don't know how the sampler might be used in the future -- for instance, given GTI's and WSU's work in distribution, it might be used to rank leaks for repair in that segment (even though the WSU study used a different version of the sampler not affected by this problem).

James Reason wrote a really great book about the Swiss cheese theory of disasters (Reason, James (1997). Managing the risks of organizational accidents. Aldershot:

Ashgate. <u>ISBN</u> 1840141042.) which is widely studied in aviation, engineering, and the fire service. In it he describes how the really terrible things that happen usually occur because there have been failures on several levels, and those failures line up to let something really bad happen.

We had a terrible example of that happen here in North Carolina a couple of years ago. A couple checked into a hotel, and the next morning they were dead. Seven weeks later, an 11 year old boy died in the same room, and although his mother survived, she had permanent brain damage.

All of that could have been avoided, because they were killed by carbon monoxide. You might have seen this on 20/20:

 $\frac{http://abcnews.go.com/US/north-carolina-best-western-room-225-opendeaths/story?id=21564280$ 

Here's how it all lined up:

- 1) The hotel pulled an old pool heater out of another property and installed it at that hotel, even though it was at the end of its life, meaning it was inefficient and was at risk for producing more carbon monoxide, and they didn't get a city inspection permit;
- 2) The vent pipe was corroded, and let the CO escape under the room where everyone was killed;
- 3) There were holes in the fire place in the room that let more CO in that would have come in otherwise;
- 4) The CO detectors that were supposed to have been installed in the rooms were actually natural gas detectors, installed by mistake.

So that's what killed the first couple.

But here's why the little boy died:

- 1) Three days after the couple was killed, a family in the room above got really sick, and complained, but the hotel didn't pay attention;
- 2) The family of the first couple raised warnings with the hotel and police that it might be CO and again no one paid attention;
- 3) The medical examiner didn't visit the scene of the first couple and see that the wife had thrown up (an important clue in CO poisoning)

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- 4) He also didn't put an expedite order on their blood work, so it sat for 40 days (two people simultaneously dead in an enclosed space -- a huge alarm bell for some toxic substance, especially CO);
- 5) He finally got the results four days before the child died in the room, but;
- 6) He sat on them for a week and by the time he finally sent them out to the local police; the child was had been killed and his mother permanently injured.

That's a tragic story, all right. And as you can imagine, the two families are suing everyone in sight that had anything to do with any of that, and I would too if I had lost a family member. Meanwhile, the DA also charged the head of the hotel management group with three counts of manslaughter, and all of those cases are still on going.

That's just one example of how tragic things can happen when we don't do everything possible to ensure people's safety. But if you do just a little bit of research, you'll see how frighteningly common that is.

So I know you'll want to address the Hi-Flow sensor failure issue immediately.

As I suggested at the start, let's do it this week. I can go up and meet with EPA tomorrow or Friday, and if you can't be there in person, you can call in, and you can have any interested parties from EDF or your production committees call in as well. i know everyone's busy, but this won't take more than an hour, and I think we should all be willing to make that much time for such a critical issue.

Just let me know when the best time for all of you is.

Thanks,

Touche'

<Howard Energy Science and Engineering Analysis of UT Data Set 2015.pdf>

<ES&T Comment on Allen et al. Methane Emissions from Process Equipment.pdf>

<Dave Allen Response to ES&T Letter.pdf>

<Touche Response to Dave Allen Comment in ESE Submitted 09 10 2015.pdf>

To: McKittrick, Alexis[McKittrick.Alexis@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]

From: DeLuca, Isabel

**Sent:** Tue 2/9/2016 3:15:23 PM

Subject: RE: meeting on Hi-Flo Sampler with Touché Howard

That's right. InsideClimate already asked the press office and they referred her to Touche.

From: McKittrick, Alexis

Sent: Tuesday, February 09, 2016 10:09 AM

To: Weitz, Melissa <Weitz.Melissa@epa.gov>; DeLuca, Isabel <DeLuca.Isabel@epa.gov>

Subject: FW: meeting on Hi-Flo Sampler with Touché Howard

We decided to ask non-EPA folks to contact Touche for the slides, correct? (see below)

Thanks,

**Alexis** 

From: Shires, Terri [mailto:terri.shires@aecom.com]

Sent: Tuesday, February 09, 2016 9:26 AM

**To:** McKittrick, Alexis < McKittrick.Alexis@epa.gov > Cc: Harrison, Matt < matt.harrison@aecom.com >

Subject: RE: meeting on Hi-Flo Sampler with Touché Howard

Alexis,

Could you please distribute the slides that Touché' presented last week?

Thank you,

Terri Shires

Senior Engineer and Project Manager, Design and Construction Services, Gulf Coast Region D +1-512-419-5466 M +1-512-497-6482

Terri.Shires@aecom.com

**AECOM** 

9400 Amberglen Blvd. Austin, Texas 78729, USA T +1-512-454-4797 aecom.com

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From: McKittrick, Alexis [mailto:McKittrick.Alexis@epa.gov]

Sent: Friday, February 05, 2016 12:56 PM

To: ralvarez@edf.org; lisa.song@insideclimatenews.org; nancy@ncwarn.org; Shires, Terri

Subject: Fwd: meeting on Hi-Flo Sampler with Touche Howard

Sent from my iPhone

https://epawebconferencing. Ex. 6 - Personal Privacy

From: Weitz, Melissa

Sent: Wednesday, December 23, 2015 4:35 PM

To: Weitz, Melissa; DeFigueiredo, Mark; Waltzer, Suzanne; McKittrick, Alexis;

Macpherson, Alex; Moore, Bruce; Thoma, Eben; Thompson, Lisa; Hambrick, Amy; Banks,

Julius; Irving, Bill **Cc:** Howard, Jodi

Subject: meeting on Hi-Flo Sampler with Touche Howard

**When:** Friday, February 5, 2016 1:30 PM-2:30 PM. **Where:** DCRoomWJCS4228AOAP/DC-OAR-OAP

Call in Ex. 6 - Personal Privacy COde 2 Ex. 6 - Personal Privacy

A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

Correspondence/Rebuttal

pubs.acs.org/est

### Comment on "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers"

llen et al. (2014) recently published measurements of Inatural gas (NG) emissions from pneumatic controllers (PCs) at NG production sites in the United States in ES&T.1 Limitations to this work include (1) faulty flow meters; (2) sensor failure in their Hi-Flow instrument; and (3) potential reset of malfunctioning PCs when installing flow meters. These problems could cause the authors' emission estimates to be underestimated by a factor of 3.

Most measurements were made by installing flow meters in the supply gas lines of the devices, which required temporarily turning off the supply gas. On March 18, 2014, in collaboration with the authors, I tested these meters (designated Fox A and Fox C) while the project was underway. The Fox A meter read an average of 65% lower than the Fox C meter (which agreed with a rotameter to within 10%). The University of Texas (UT) team replaced the meter cable, but problems persisted and the Fox A meter was not tested further that day. The authors continued using the Fox A meter during their program but without incorporating the March 18 test results; the authors only noted that Fox A read 37% lower than Fox C during post project calibration due to "condensation of an oily substance on the sensor". However, even with this correction, measurements made with Fox A were a factor of 2 lower than Fox C on March 18. Volatiles likely accumulated and dissipated on both meters throughout the project; with calibrations only before and after the project, and the large difference in Fox A's measurements on March 18 compared to these corrections, the accuracy of these meters is highly questionable.

Although the authors cite the agreement of five Hi-Flow sampler and meter measurements for emission rates >6 scfh, at least four of those comparisons were for Fox A. Additionally, four of these comparisons were made at either the same or nearby sites. Consequently, these comparisons primarily show meter performance for a short time frame and for one meter. In contrast, all available comparisons of Hi-Flow and meter measurements show on average the meters read only 71% of the Hi-Flow measurements; removing one Hi-Flow measurement that the authors thought low due to incomplete capture indicates on average the meters read only 58% of the Hi-Flow measurements.

Also during the March 18 tests, the UT Bacharach Hi-Flow sampler failed to transition between low and high range sensors, underestimating emission rates by up to 2 orders of magnitude.<sup>2</sup> The instrument was recalibrated after this occurred, eliminating this failure for the rest of that day, but the performance of the instrument before and after our testing is unknown. This could cause underestimates in the Hi-Flow measurements made during this project<sup>1</sup> and previously.<sup>3</sup>

Finally, in my experience, manual actuation of malfunctioning PCs with high bleed rates may reset them to lower bleed rates; turning the supply gas off and on to install meters might have similarly reset devices. Figure 1 compares intermittent PC

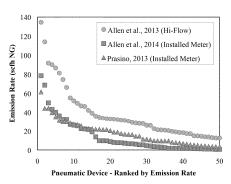


Figure 1. Intermittent pneumatic device emission rates measured by meters and Hi-Flow Sampler. The lower peak emitters observed in the studies made by installing meters is likely due to resetting malfunctioning controllers by turning the supply gas to devices off and back on during meter installation.

bleed rates from three studies: Allen et al. (2013);3 Prasino (2013),4 which also installed meters, and the study under discussion; and Allen et al. (2014).1 The two studies which installed meters have significantly lower peak emitters than the previous study done by Hi-Flow,3 which did not require stopping the supply gas. The current study 1 noted that intermittent PCs with bleed rates larger than 40.2 scfh were malfunctioning; only 1.3% of the intermittent PCs in (1) were above this bleed rate compared to 11% in the previous study.3 Consequently, the scarcity of high emitters in the current study<sup>1</sup> is likely due to reset devices, because other factors, that is, greater liquid production rates, would not be sufficient to cause the greater occurrence of high emitters observed in (3). The effect of these missing malfunctioning controllers can be estimated by adding the emission rates for intermittent PCs observed by (3) that are greater than the largest emission rate for intermittent PCs observed in (1). This would increase the average emission rate from intermittent PCs in the current study by 81%. If the number of missing high emitters is adjusted for the increased sample size of the current study compared to (3), then the average emission rate would increase by 298%.

#### Touché Howard\*

Indaco Air Quality Services, Inc., Durham, North Carolina 27713, United States



Corresponding Author

\*Phone: 919-943-9406; e-mail: touche howard@earthlink.net.

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Environmental Science & Technology

Correspondence/Rebuttal

#### Notes

The author declares no competing financial interest



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#### **Energy Science & Engineering**

# Energy Science & Engineering

# Response to "Comment on "University of Texas study underestimates national methane emissions inventory at natural gas production sites due to instrument sensor failure""

Journal:	ENERGY SCIENCE & ENGINEERING		
Manuscript ID	Draft		
Wiley - Manuscript type:	Response		
Search Terms:	Environment, Natural gas, Safety		
Abstract:	The authors of the University of Texas (UT) study dispute my analysis in "University of Texas study underestimates national methane emissions inventory at natural gas production sites due to instrument sensor failure" demonstrating that sensor transition failure affected their Bacharach Hi-Flow Sampler (BHFS) measurements at natural gas production sites. Although I addressed most of their arguments in the original paper, here I summarize the relevant evidence and also provide a simplified comparison of their downwind tracer measurements and on-site measurements. This comparison provides clear independent verification, using the authors' own data, that their BHFS measurements were too low at sites with lower methane content in the wellhead gas. Because the BHFS sensor failure presents a critical safety issue, and their incorrect defense of this work distracts from this problem, I call upon the authors and sponsors of the UT study to retract the UT BHFS measurement data in order to ensure the safety of industry personnel and to protect the health of communities near oil and natural gas facilities.		

SCHOLARONE\*\*
Manuscripts

#### **Energy Science & Engineering**

Dr. Allen and colleagues from the University of Texas (UT) (1) argue that sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS) did not affect their 2013 UT study (2) as I presented in (3). This is a welcome and critically important discussion because sensor failure in the BHFS may cause both underreporting of methane (CH<sub>4</sub>) emissions and underestimation of the health effects from air emissions at oil and natural gas (NG) facilities. Most importantly, however, the BHFS is also used to prioritize the repair of NG leaks, and if a large leak were not repaired because the BHFS underestimated it, this could lead to catastrophic component failure and/or explosion.

Although the rebuttal by (1) contends that the BHFS has been used since the 1990's, the BHFS has actually only been commercially available since 2003. High flow sampling measurements of NG leaks made prior to this were done with custom built instruments based on my design, which Bacharach, Inc. then developed into the BHFS. However, I am not affiliated with Bacharach, Inc. and I was not associated with the development of the BHFS.

The primary evidence of sensor failure is not the lack of high emitters in the UT BHFS data set (2) as stated by (1) but rather the direct experimental observance of this failure, which has been reported in (4) and (5), and, as summarized in (3), has been observed in four out of six samplers that were tested using NG with CH<sub>4</sub> content of < 91%. However, because the UT BHFS data set (2) contains measurements of several different types of sources with wide ranges of natural gas compositions, it provides a unique opportunity to evaluate the possibility that the occurrence of sensor failure might be widespread. It is certainly important to recognize that the BHFS measurements in (2) were biased low by sensor failure so that this data set is not relied upon to inform public policy. However, the much more important result of my analysis (3) of the UT BHFS data set is that sensor failure could indeed be widespread, since it appears to have occurred when measuring NG streams with CH<sub>4</sub> concentrations as high as 97%. This means that BHFS measurements throughout all sectors of the NG industry could be affected.

A third point of confusion is the contention by (1) that air pollution regulations in the Rocky Mountain region resulted in lower emission rates in that region, and that this explains the lack of high emitters at sites with lower  $CH_4$  content observed in their study because that region also had a lower  $CH_4$  content in the wellhead gas. Air pollution regulations might indeed result in lower emission rates in the Rocky Mountain region, but my analysis in (3) explains in detail that this is clearly not the cause of the scarcity of high emitters at sites with wellhead gas of lower  $CH_4$  content. To summarize, my analysis explains that:

- 1) Even when the Rocky Mountain region is excluded, there are still almost four times fewer high emitters at sites with wellhead NG compositions < 91% CH<sub>4</sub> than sites with > 91% CH<sub>4</sub>;
- 2) Pneumatic device emissions measured using flowmeters in a UT follow-up study (6) show a complete reversal of the pattern of pneumatic device emissions measured by BHFS in the UT study (2), i.e., when measured by flow meters, there was a larger occurrence of high emitters at sites with low well head gas CH<sub>4</sub> content;
- 3) Emission rates measured by BHFS reported by (2) within a single region Appalachia show a dramatic pattern of decreasing occurrence of high emitters as wellhead CH<sub>4</sub> concentration decreases over a narrow range from 98 to 95% CH<sub>4</sub>; and

4) Although the downwind tracer measurements (discussed in further detail below) made by (2) confirm that emission rates in the Rocky Mountain region were lower than other regions, these measurements also confirm that the BHFS measurements are too low at sites with low wellhead gas CH<sub>4</sub> content, even in the Rocky Mountain region.

It was also asserted by (1) that both field and laboratory testing showed little evidence of the sensor failure. As described in (3), I tested the sampler used in the UT study after the publication of their initial results in (2) in the presence of members of the UT field team and observed the sensor failure during this testing (4). This failure occurred even though the sampler had been upgraded to a new generation of firmware after it was used to conduct the measurements made during the initial UT study (2). After I conducted this field testing, I immediately interviewed two experienced BHFS technicians not associated with the UT team who reported that the new generation of firmware had eliminated problems in their samplers that caused leaks too be reported too low. Given the dramatic improvement in performance of samplers reported by these technicians using the updated generation of firmware, it is not surprising that the sensor failure only occurred sporadically in the UT sampler during the field tests and was not observed in their laboratory tests. Indeed, it is rather surprising that sensor failure occurred at all in a unit with updated firmware, although this highlights that the factors affecting sensor failure are still not well understood. I immediately relayed these reports of improved performance of samplers with updated software to the UT team in March of 2013, so the authors of (1) and (2) are well aware that the performance of the UT sampler could have been much worse when it was used for the original UT study (2), during which time it had older firmware. It is also interesting to note that during the March 2013 field testing, the UT team had a second BHFS that they did not allow me to test, stating that it had too many problems to make testing it worthwhile, although the nature of those problems was not specified.

The rebuttal (1) further asserts that the reason sensor transition failure occurred in the UT sampler during the field testing I conducted was that the proper UT calibration protocol was not followed. As I explained in (3), the UT team made no effort to conduct calibrations after the instrument was turned off and on but only did so after sensor failure was noted. Consequently, in contrast to what they have stated in (1), it does not appear that the UT protocol was to calibrate any time the instrument was turned on.

Allen and his colleagues (1) also state that because the average emission rates of pneumatic devices measured by flow meters in their follow-up study (6) are lower than those measured by their BHFS in (2), this disproves the possibility of sensor failure since sensor failure should cause the BHFS measurements to be lower. However, as I explained in (3), the pneumatic device data collected by BHFS (2) were clearly not a random sample but instead focused only on emitting devices and inadvertently excluded zero emission sources. This is one reason why average pneumatic device emission rates calculated from the BHFS data (2) are higher than those calculated from the flow meter data (6). Additionally, much of the pneumatic device data collected by flow meters (6) was likely biased low due to calibration problems. The authors of (6) only calibrated their meters before and after their field work, and claim in their supplemental information that they only became aware of a calibration problem with one meter during their post project calibration. However, as I reported in (7), I also tested the UT flow meters in March of 2013 while the measurements for the follow-up study (6) were ongoing, again in the presence of the UT field team. During these tests, one of their two primary meters indicated flow rates that were a factor of three lower than the actual flow rates released through the meters. Even

#### **Energy Science & Engineering**

after applying their post project calibration correction (6), the flow rates measured by this faulty meter during these tests would still be a factor of two lower than the actual flow rates. These two additional failures of quality assurance – the inadvertent exclusion of zero emitters from a supposedly random sample of devices in (2) and the inadequate calibration of flow meters in (6) – further highlight the need for dramatic improvements in greenhouse gas measurements programs.

Allen and colleagues (1) also maintain that infrared camera data showed no evidence that the BHFS did not accurately measure high emitters; however, there is ample evidence that infrared camera visualization cannot be currently used to quantify leaks. For instance, during the Ft. Worth Air Quality study (8), daily QA checks on the IR camera indicated variations in factors of up to 15 in the distance at which a known leak could be identified, much less quantified, under calm conditions. This large variability, even under calm conditions, demonstrates the huge uncertainty in trying to quantify emission rates with an IR camera, since any air movement near the leak would dramatically increase this variability.

Finally, their rebuttal (1) also states that my comparison (3) of the downwind tracer measurements to the on-site emissions measurements in the UT study (2) is "complex" and obscures the fact that the average emission rates from wells in the Rocky Mountain region were too small for the sensor failure to have occurred. In particular, they state: "The average per well emissions in the Rocky Mountains, made using independent downwind sampling at sites with 40 wells, were low. The average emission rates from these wells were less than half of the emissions that would be expected from just one high emission rate source per well that Howard (2015) argues should be prevalent at sites with high methane concentrations. Simply stated, if there were missing emissions of the magnitude asserted by Howard (2015), they would have significantly increased measured downwind concentrations."

However, this claim by (1) ignores the fact that the downwind tracer technique was used to measure  $CH_4$  emissions not from individual wells but from sites with an average of almost five wells per site, so the emission rates per site are much higher than the emission rates per well. In fact, the average emission rate per site measured by downwind tracer in the Rocky Mountain region was 0.66 scfm, over 50% greater than the expected BHFS sensor transition threshold of 0.4 scfm at a sample flow of 8 scfm. If the BHFS sample flow were reduced to 4 scfm due to low battery power or a tightly wrapped enclosure, then sensor transition failure could occur when measuring a source as small as 0.2 scfm. Consequently, a single measurement of a high emitter at these sites that was biased low by sensor failure could cause the observed underreporting of BHFS measurements compared to the tracer data.

To illustrate this, and because Dr. Allen and colleagues (1) found my comparison in (3) of their downwind tracer and on-site data (2) to be complex, I have tried to simplify that analysis here. Figure 1 presents the downwind tracer and on-site data from the UT study (2). For this analysis, I have removed only the two sites at which 98% or more of the reported on-site totals were comprised of estimated emissions, as opposed to actual BHFS measurements, since such a large fraction of estimated emissions would prevent a reasonable evaluation of the BHFS performance.

As seen in Figure 1, the downwind tracer data do in fact indicate that there are real regional differences in  $CH_4$  emissions from natural gas production, as (1) have asserted and as I have acknowledged in (3).

However, Figure 1 also shows clearly that the lower emissions in the Rocky Mountain region do not preclude the occurrence of BHFS sensor failure. When comparing the results on a site by site basis, the on-site totals (which as noted previously were a combination of BHFS measurements added to estimates of sources not measured) are substantially lower than the downwind tracer results for the Rocky Mountain and Mid-Continent sites where  $CH_4$  content was less than 82%, and substantially higher for sites in Appalachia where  $CH_4$  content was greater than 97% (sensor transition failure is much more likely at  $CH_4$  concentrations less than 97% (3)). Only one out of 13 sites with  $CH_4$  content < 82% (RM-5) had reported on-site emissions greater than the emissions measured by tracer, while all four sites with  $CH_4$  content > 97% had on-site emissions greater than those measured by tracer. The ratio of total on-site emissions to downwind tracer emissions for each region was as follows: Mid-Continent: 0.586; Rocky Mountain: 0.461; and Appalachia: 1.44.

Since the reported on-site emissions were greater than those measured by downwind tracer at all sites with well gas content of  $CH_4 > 97\%$  (the Appalachia region) where the BHFS likely functioned properly, I conclude that the estimation methods used by the UT study (2) actually overestimate emission rates as compared to actual whole-site emissions measured by downwind tracer analysis. Consequently, although this simplified comparison indicates that the on-site data are a factor of two too low at the Mid-Continent and Rocky Mountain sites, the actual effect of BHFS sensor failure is probably larger because the overestimates of emissions from the sources that were not measured somewhat obscures the underreporting by the BHFS, and I've discussed this in detail in (3). Therefore, although this direct comparison of the downwind tracer measurements to the on-site data for each site independently verifies the BHFS sensor failure, it does not reflect the full magnitude of the problem.

Given that the BHFS sensor failure can cause underreporting of natural gas emission rates which could create critical safety, health, and environmental problems, it is disappointing that (1) are willing to ignore the clear evidence – provided by their own downwind tracer measurements – of the effects of sensor failure in the UT BHFS (2) data set. The lead author of (1) and (2) served as the chair of the EPA Science Advisory Board during the period of research conducted by (2), and as such has a special obligation to disclose this issue since the BHFS is an EPA approved instrument. The BHFS is currently the standard instrument in the natural gas industry worldwide for measuring leak rates, and although upgrading firmware may reduce sensor failure, it does not eliminate it, and it is likely that most BHFS's in use have older firmware more susceptible to sensor failure. The presence of such a problem that can result in large leaks being reported as an order of magnitude or more lower than they actually are presents a frightening safety issue. It may have also caused many CH<sub>4</sub> emission inventories to be biased low, including those compiled by the USEPA Subpart W Greenhouse Gas Reporting program (9), the American Carbon Registry (10), and the United Nations Clean Development Mechanism (11).

For the last 12 years I have served as a professional firefighter, and in that role I have seen the tragic consequences that can occur when safety issues are ignored. Unfortunately, the misguided defense by such prominent researchers (1) of the UT BHFS data set (2) creates a distraction from the critical safety, health, and environmental problems that the BHFS sensor failure presents to the oil and NG industry. I call upon the authors and sponsors of the UT study (2) to meet their obligations to the safety of industry personnel and to the health of communities near oil and NG facilities by retracting the UT BHFS data set (2) so that this critically important problem can be recognized and addressed immediately.

#### **Energy Science & Engineering**

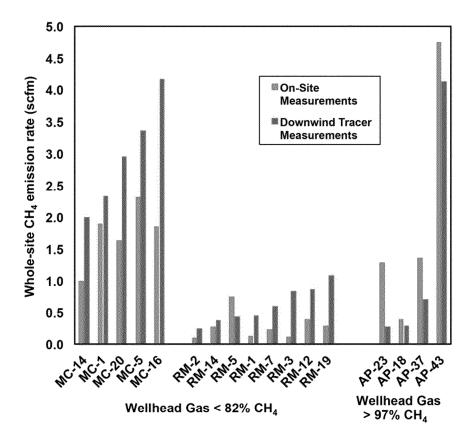
#### References Cited

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  Methodology for the Conversion of High-Bleed Pneumatic Controllers in Oil and Natural Gas
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   Approved baseline methodology AM0023: Leak reduction from natural gas pipeline compressor or gate stations (Version 3). Available at: https://cdm.unfccc.int/filestorage/J/Y/2/JY2L0XEKMB3HD18T7RPO6ZSFCQINGA/EB50 repan04

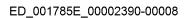
AM0023 ver3.pdf?t=MDJ8bnVnc2hzfDC3Xz7EsZbGIMHnVQLYxRyn (accessed 10 September 2015).

#### **Figure Captions**

Figure 1. Comparison of downwind tracer measurements to reported on-site emission rates (compiled from BHFS measurements and estimates of sources not measured) in the UT study (2). Sites with lower CH4 wellhead gas content, where the BHFS is likely to experience sensor failure, have dramatically lower on-site emission rates compared to emission rates at the same sites measured by downwind tracer techniques. This comparison provides independent corroboration of the BHFS sensor failure, even in the Rocky Mountain region where tracer measurements indicate lower regional emission rates. BHFS = Bacharach Hi-Flow Sampler; MC = Mid-continent; RM = Rocky Mountain; AP = Appalachia.



70x66 M M (300 X 300 DPI)



**To:** Weitz, Melissa[Weitz.Melissa@epa.gov]; Bylin, Carey[Bylin.Carey@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; McKittrick, Alexis[McKittrick.Alexis@epa.gov]

From: DeLuca, Isabel

**Sent:** Mon 7/6/2015 5:47:17 PM

Subject: RE: ACTION: Inside Climate News: DDL: 7/10: methane sampling question

Hi all,

Apologies—I had forgotten that we had a similar question on this reporter back in May. I think OAQPS may have handled that. I think we're off the hook—they'll probably just recycle what they sent last time.

Thanks,

Isabel

From: DeLuca, Isabel

Sent: Monday, July 06, 2015 10:13 AM

To: Weitz, Melissa; Bylin, Carey; Waltzer, Suzanne; DeFigueiredo, Mark; McKittrick, Alexis

Cc: Gunning, Paul; Franklin, Pamela

Subject: FW: ACTION: Inside Climate News: DDL: 7/10: methane sampling question

Hi all,

We have a request from Inside EPA seeking comment on an upcoming study (embargoed copy attached) that suggests some emissions testing equipment (the Bacharach Hi-Flow Sampler) underreports emissions – leading to low national emissions estimates, and potential errors in data reported to GHGRP.

# Ex. 5 - Deliberative Process

Here's some language adapted from what we've used for the inventory in the past—I'd love your

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input. Should we add anything more about GHGRP? Let me know what you think.

### Ex. 5 - Deliberative Process

I'll also	run this	paper,	and our	response,	by	OAQPS	before	sending	up,	but wanted	CCD's	s input
first												

Thanks,

Isabel

From: Colaizzi, Jennifer C.

**Sent:** Monday, July 06, 2015 8:41 AM **To:** DeLuca, Isabel; Sutton, Amanda

Subject: ACTION: Inside Climate News: DDL: 7/10: methane sampling question

Hi all:

Outlet: Inside Climate News

Reporter: Lisa Song

DDL: 7/10

Reporter's original request was to interview Roger Fernandez, but she is on deadline and received an out of office from him. She updated her request to interview someone from EPA who was on the Fall 2014 conference call with Fernandez and Howard.

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I'm emailing to request a phone interview with Roger Fernandez (cc'ed) during this coming week (July 6-10). Last fall (around October), Mr. Fernandez organized a conference call with EPA staff and air quality consultant Touche Howard. The purpose of the call was to listen to a presentation from Mr. Howard about his concerns for the Bacharach Hi-Flow Sampler--an EPA-approved methane sampling device. Mr. Howard believed he had found a flaw in the sampler that resulted in underestimating methane emissions. During the call, Mr. Howard presented his findings and discussed them with the EPA staff who were present, including Mr. Fernandez.

I have spoken with Mr. Howard, and he suggested I talk to Mr. Fernandez. I believe Mr. Fernandez is no longer with the EPA Natural Gas Star Program--however, my questions are about the presentation from last fall that he heard while he was still with the program.

In addition, Mr. Howard's has an upcoming paper (embargoed proof attached) that will soon be published, based on his Bacharach testing. If Mr. Fernandez has any thoughts on the paper, I'd be glad to discuss that too. If not, we can just stick with his thoughts on Mr. Howard's presentation.

To: McKittrick, Alexis[McKittrick.Alexis@epa.gov]

From: Weitz, Melissa

**Sent:** Fri 2/5/2016 7:01:26 PM

Subject: Re: meeting on Hi-Flo Sampler with Touche Howard

It's fine-it's also been up on the projector screen for about 10 mins...

Sent from my iPhone

On Feb 5, 2016, at 1:58 PM, McKittrick, Alexis < McKittrick. Alexis@epa.gov> wrote:

This is what I sent. Didn't mean to include the bit at the bottom.

Sent from my iPhone

Begin forwarded message:

From: "McKittrick, Alexis" < McKittrick. Alexis@epa.gov>

**Date:** February 5, 2016 at 1:56:18 PM EST

**To:** "ralvarez@edf.org" <ralvarez@edf.org>, "lisa.song@insideclimatenews.org" <</ri>
!isa.song@insideclimatenews.org>, "nancy@ncwarn.org" <nancy@ncwarn.org>,

"terri.shires@aecom.com" < terri.shires@aecom.com>

Subject: Fwd: meeting on Hi-Flo Sampler with Touche Howard

Sent from my iPhone

https://epawebconferencing.acms.com/r2fk2tdpn9x/

From: Weitz, Melissa

Sent: Wednesday, December 23, 2015 4:35 PM

To: Weitz, Melissa; DeFigueiredo, Mark; Waltzer, Suzanne; McKittrick, Alexis;

Macpherson, Alex; Moore, Bruce; Thoma, Eben; Thompson, Lisa; Hambrick, Amy; Banks,

Julius; Irving, Bill Cc: Howard, Jodi

Subject: meeting on Hi-Flo Sampler with Touche Howard

When: Friday, February 5, 2016 1:30 PM-2:30 PM. Where: DCRoomWJCS4228AOAP/DC-OAR-OAP

Call in Ex. 6 - Personal Privacy Code Ex. 6 - Personal Privacy

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A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

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To: Weitz, Melissa[Weitz.Melissa@epa.gov] From: McKittrick, Alexis Sent: Mon 1/25/2016 5:11:07 PM **Subject:** RE: tomorrow's meeting Thanks!!! From: Weitz, Melissa **Sent:** Monday, January 25, 2016 12:05 PM **To:** McKittrick, Alexis < McKittrick. Alexis@epa.gov> Subject: Re: tomorrow's meeting It's canceled. Trying to figure out how to cancel the invite from my phone. Sent from my iPhone On Jan 25, 2016, at 11:54 AM, McKittrick, Alexis < McKittrick. Alexis@epa.gov > wrote: Hi Melissa, Any read of if the Touche Howard meeting for tomorrow will be postponed? I am guessing he needs to travel up today for it, and the roads are still terrible. I am hoping to telework tomorrow, but I would try to come in if this meeting is still on. I think the more EPA folks in the room the better. Let me know when you can. Thanks!

Alexis McKittrick, Ph.D.

Alexis

Climate Change Division

U.S. Environmental Protection Agency

Phone: 202-343-9153

E-mail: mckittrick.alexis@epa.gov

To: Weitz, Melissa[Weitz.Melissa@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]

From: McKittrick, Alexis

Sent: Mon 2/1/2016 7:05:25 PM

Subject: RE: GHGI public review drafts

Melissa,

I am coming in on Friday, so I'll be here for the Paul briefing (and the Touche Howard meeting). I can make the Sarah briefing too, but Mark and I can discuss whether it makes sense for both of us to attend or not.

Alexis

From: Weitz, Melissa

Sent: Monday, February 01, 2016 1:01 PM

To: DeFigueiredo, Mark < DeFigueiredo. Mark@epa.gov>; McKittrick, Alexis

<McKittrick.Alexis@epa.gov>
Subject: GHGI public review drafts

I added you both to the series of briefings on the GHGI public review drafts. It's up to you guys how you'd like to cover-you don't both need to attend each briefing and if there is a meeting neither of you can make that's probably okay too. Also leaving it up to you if you want to invite Julius to any/all of the briefings. Thank you!

From: McKittrick, Alexis

Location: DCRoomWJCS4228AOAP/DC-OAR-OAP

Importance: Normal

Subject: Accepted: hold for meeting on Hi-Flo Sampler with Touche Howard

**Start Date/Time:** Tue 1/26/2016 4:00:00 PM Tue 1/26/2016 5:00:00 PM

To: Thoma, Eben[Thoma.Eben@epa.gov]; Birnur Guven (bguven@harcresearch.org)[bguven@harcresearch.org]; Natalie Pekney[Natalie.Pekney@netl.doe.gov]; amy.townsend-small@uc.edu[amy.townsend-small@uc.edu]; anna.karion@noaa.gov[anna.karion@noaa.gov]; Anthony O'Brien[anthonyo@princeton.edu]; Bill Hirst[bill.hirst@shell.com]; Brian Lamb[blamb@wsu.edu]; Brian Nathan [brian.nathan@utdallas.edu]; Charles Boller[cboller@craworld.com]; Chris Rella[rella@picarro.com]; Clark, Nigel[Nigel.Clark@mail.wvu.edu]; Colm Sweeney[colm.sweeney@noaa.gov]; Darrell Anderson[anddarrell@gmail.com]; Dave Schaefer[captdaveschaefer@gmail.com]; David Steele[dsteele@picarro.com]; david.lary@utdallas.edu[david.lary@utdallas.edu]; 'Derek Johnson'[Derek.Johnson@mail.wvu.edu]; 'desiree.plata@duke.edu'['desiree.plata@duke.edu']; Don Blake[drblake@uci.edu]; Drew Nelson[dnelson@edf.org]; ecrosson@picarro.com[ecrosson@picarro.com]; Eric Kort[eakort@umich.edu]; 'Gabrielle Petron - NOAA Affiliate'[gabrielle.petron@noaa.gov]; Isobel Simpson[isimpson@uci.edu]; 'Jackson@duke.edu'['Jackson@duke.edu']; 'Joe.von\_Fischer@colostate.edu'|''Joe.von\_Fischer@colostate.edu']; Josette Marrero[jmarrero@uci.edu]; Kelsey Monk[kmonk@edf.org]; Ken Davis[kjd10@psu.edu]; lanxin.lindsay@gmail.com[lanxin.lindsay@gmail.com]; Malcolm Argyle[argyle@sgl.com]; mcambali@purdue.edu[mcambali@purdue.edu]; McKain, David[David.McKain@mail.wvu.edu]; Morgan Gallagher[morgan.gallagher@duke.edu]; mzondlo@princeton.edu[mzondlo@princeton.edu]; 'plaine@uh.edu'['plaine@uh.edu']; 'pshepson@purdue.edu'['pshepson@purdue.edu']; Ramon Alvarez[RAlvarez@edf.org]; Rob Bennett[robert.bennett@atmosenergy.com]; Robert Harriss[rharriss@edf.org]; Sol Meyer[sgltexas@sgl.com]; Steve Conley[sconley@scientificaviation.com]; Steve Edburg[sedburg@wsu.edu]; Talbot, Robert[rtalbot@Central.UH.EDU]; Tegan Lavoie[tlavoie@purdue.edu]; Thomas Lauvaux[thomas.lauvaux@carbonnowcast.com]; Tom Ferrara[tferrara@craworld.com]; Touche Howard[touche howard@earthlink.net]; Tracy Tsai[ttsai@picarro.com]; Daniel Jacob[djacob@fas.harvard.edu]; Doug Blewitt[dougblewitt@comcast.net]; Francis O'Sullivan[frankie@mit.edu]; Steve Hanna[hannaconsult@roadrunner.com] Cc: Lucy Kalunde[lkalunde@edf.org]; Kelsey Monk[kmonk@edf.org]

From: David Lyon

Thur 12/19/2013 9:49:46 PM Sent:

Subject: Barnett Campaign meeting January 23 & 24 in Denver

### Greetings,

The Barnett Campaign meeting will be January 23 & 24 in Denver. Yes, I'm aware that Denver is cold in January, but it is the most convenient location to bring people together. EDF will book a block of rooms and meeting place at a hotel near the Denver International Airport. We plan on starting the meeting around 1:00 pm Thursday and ending around 4:00 pm Friday, which should allow most people to stay only one night at the hotel. Lucy Kalunde at EDF will book your flights. Please let us know if you are attending and send Lucy (lkalunde@edf.org) the following information as soon as possible.

- 1. Name (First, Middle, Last)
- 2. DOB

- 3. Preferred Contact Phone #
- 4. Preferred Airport (realize some people may be travelling already)
- 5. Any other important info we'll need to book a good flight for them.

Thanks,

David

marketo.

David Lyon

Research Analyst

**Environmental Defense Fund** 301 Congress Avenue, Suite 1300

Austin, TX 78701 (512) 691-3414 dlyon@edf.org

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which may be a computer program. This attached computer program could contain a computer virus which could cause harm to EPA's computers, network, and data. The attachment has been deleted.

This was done to limit the distribution of computer viruses introduced into the EPA network. EPA is deleting all computer program attachments sent from the Internet into the agency via Email.

If the message sender is known and the attachment was legitimate, you should contact the sender and request that they rename the file name

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extension and resend the Email with the renamed attachment. After receiving the revised Email, containing the renamed attachment, you can rename the file extension to its correct name.

For further information, please contact the EPA Call Center at  $(866)\ 411-4$ EPA (4372). The TDD number is  $(866)\ 489-4900$ .

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From: Weitz, Melissa

Location: DCRoomWJCS4228AOAP/DC-OAR-OAP

Importance: Normal

Subject: meeting on Hi-Flo Sampler with Touche Howard

**Start Date/Time:** Fri 2/5/2016 6:30:00 PM Fri 2/5/2016 7:30:00 PM

Call in Ex. 6 - Personal Privacy | code Ex. 6 - Personal Privacy

A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

From: David Lyon

ReadyTalk Dial-In Number(s): Location: Ex. 6 - Personal Privacy Access Code: Ex. 6 - Personal Privac

Importance: Normal

Subject: Barnett Campaign Workshop January 24 Fri 1/24/2014 3:00:00 PM Start Date/Time: End Date/Time: Fri 1/24/2014 11:00:00 PM

,,,,

For people attending in person, we will meet in Room B of the Marriott Denver Airport at Gateway Park. Here is information for joining on Friday by web or phone.

### **PARTICIPANTS:**

Participants, click here to join the meeting: https:// Ex. 6 - Personal Privacy

https://

Audio Conference Information:

Dial-In Number(s):

U.S. & Canada: Ex. 6 - Personal Privacy

Access Code: Ex. 6 - Personal Privacy

For technical support:

U.S. and Canada: 800.843.9166 International: 303.209.1600 Email: help@readytalk.com

Web: http://www.readytalk.com/support

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From: Fernandez, Roger

**Location:** By phone - see call in number

Importance: Normal

Subject: Hi-Flow Sampler Issues - How it relates to Subpart W and Possibly Quad O

**Start Date/Time:** Wed 10/1/2014 8:00:00 PM Wed 10/1/2014 8:30:00 PM

Hello Everyone,

This meeting request is a follow up to a call I had with Mr. Touche Howard and Mr. Thomas Ferrara regarding their experience with the Hi-flow sampler and some potential measurement issues associated with it.

As they noted, their primary concern is that this may result in important safety, measurement and environmental issues. They believe that this could be solved by users updating their firmware and conducting daily calibrations (as opposed to just bump tests).

I am not sure if / what authority we have in this regard but as this potential measurement error problem could impact our inventory numbers and Quad O applicability assessments, I suggest we have this discussion.

Please use the following call in number:

Dial: Ex. 6 - Personal Privacy

THANKS!!

From: Weitz, Melissa.....

Location: Ex. 6 - Personal Privacy COde Ex. 6 - Personal Privacy

Importance: Normal

Subject: monthly methane research and data call Start Date/Time: Wed 9/30/2015 5:00:00 PM End Date/Time: Wed 9/30/2015 6:00:00 PM

Untitled Untitled

A few of us in OAR and ORD been having monthly general coordination check in calls on methane work.

We've decided to expand the invitation list for the call to include to others interested in methane research and data and to focus on specific topics or research papers each month, and also allow time for updates on activities.

For the 9/29 call, our plan is to discuss new research on Hi Flow samplers. I will send around some papers in advance of the call. Let me know if you have any questions. Thanks!

To: Weitz, Melissa[Weitz.Melissa@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; McKittrick, Alexis[McKittrick.Alexis@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Bylin, Carey[Bylin.Carey@epa.gov]; Macpherson, Alex[Macpherson.Alex@epa.gov]; Moore, Bruce[Moore.Bruce@epa.gov]; Hambrick, Amy[Hambrick.Amy@epa.gov]; Thompson, Lisa[Thompson.Lisa@epa.gov]; Thoma, Eben[Thoma.Eben@epa.gov]; Snyder, Jennifer[Snyder.Jennifer@epa.gov]; Alsalam, Jameel[Alsalam.Jameel@epa.gov]

Subject: monthly methane research and data call

a411 7.pdf

AWAM VOC Brantley.pdf

2015 Howard ESE HI FLO and UT EDF implications.pdf

Howard 2015b JAWMA high flow sensor.pdf

The 11/12/2015 call will focus on new research on Hi Flow samplers. Attached are some key papers. a411 7.pdf 2015 Howard ESE HI FLO and UT EDF implications.pdf AWAM VOC Brantley.pdf Howard 2015b JAWMA high flow sensor.pdf

To: Weitz, Melissa[Weitz.Melissa@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; McKittrick, Alexis[McKittrick.Alexis@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Bylin, Carey[Bylin.Carey@epa.gov]; Macpherson, Alex[Macpherson.Alex@epa.gov]; Moore, Bruce[Moore.Bruce@epa.gov]; Hambrick, Amy[Hambrick.Amy@epa.gov]; Thompson, Lisa[Thompson.Lisa@epa.gov]; Thoma, Eben[Thoma.Eben@epa.gov]; Snyder, Jennifer[Snyder.Jennifer@epa.gov]; Alsalam, Jameel[Alsalam.Jameel@epa.gov]; Gamas, Julia[Gamas.Julia@epa.gov]; Beeler, Cindy[Beeler.Cindy@epa.gov]; Shine, Brenda@epa.gov]

Subject: (adding webinar link) monthly methane research and data call

3/22 meeting will focus on pneumatic controller measurements

https://epawebconferencing Ex. 6 - Personal Privacy

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# University of Texas study underestimates national methane emissions at natural gas production sites due to instrument sensor failure

Touché Howard

Indaco Air Quality Services, Inc., Durham, North Carolina

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#### Correspondence

Touché Howard, Indaco Air Quality Services, Inc., Durham, NC. Tel: (919) 943-9406; E-mail: touche.howard@indacoaqs.com

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#### **Abstract**

The University of Texas reported on a campaign to measure methane  $(CH_A)$ emissions from United States natural gas (NG) production sites as part of an improved national inventory. Unfortunately, their study appears to have systematically underestimated emissions. They used the Bacharach Hi-Flow® Sampler (BHFS) which in previous studies has been shown to exhibit sensor failures leading to underreporting of NG emissions. The data reported by the University of Texas study suggest their measurements exhibit this sensor failure, as shown by the paucity of high-emitting observations when the wellhead gas composition was less than 91% CH<sub>4</sub>, where sensor failures are most likely; during follow-up testing, the BHFS used in that study indeed exhibited sensor failure consistent with under-reporting of these high emitters. Tracer ratio measurements made by the University of Texas at a subset of sites with low CH4 content further indicate that the BHFS measurements at these sites were too low by factors of three to five. Over 98% of the CH 4 inventory calculated from their own data and 41% of their compiled national inventory may be affected by this measurement failure. Their data also indicate that this sensor failure could occur at NG compositions as high as 97% CH<sub>4</sub>, possibly affecting other BHFS measurement programs throughout the entire NG supply chain, including at transmission sites where the BHFS is used to report greenhouse gas emissions to the United States Environmental Protection Agency Greenhouse Gas Reporting Program (USEPA GHGRP, U.S. 40 CFR Part 98, Subpart W). The presence of such an obvious problem in this high profile, landmark study highlights the need for increased quality assurance in all greenhouse gas measurement programs.

### Introduction

The climatic benefits of switching from coal to natural gas (NG) depend on the magnitude of fugitive emissions of methane ( $\mathrm{CH_4}$ ) from NG production, processing, transmission, and distribution [12, 13, 27]. This is of particular concern as the United States increasingly exploits NG from shale formations: a sudden increase in  $\mathrm{CH_4}$  emissions due to increased NG production could trigger climate "tipping points" due to the high short-term global warming potential of  $\mathrm{CH_4}$  (86× carbon dioxide on a 20-year time scale) [19]. The United States Environmental

Protection Agency (USEPA) estimates  $\mathrm{CH_4}$  emissions from the NG supply chain by scaling up individual ground-level measurements, mostly collected by reporting from industry [26]. However, some recent studies have questioned whether these "bottom-up" inventories are too low, since airborne measurements indicate that  $\mathrm{CH_4}$  emissions from NG production regions are higher than the inventories indicate [5, 14, 17, 20, 21].

In order to help determine the climate consequences of expanded NG production and use, and to address the apparent discrepancy in top-down and bottom-up measurements, the University of Texas (UT) at Austin and the

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UT Study Underestimates Methane Emissions

Environmental Defense Fund launched a large campaign to measure CH4 emissions at NG production sites in the United States [1]. This study used both existing EPA GHG inventory data and new measurements to compile a new national inventory of CH<sub>4</sub> emissions from production sites. Forty-one percent of this new inventory was based on measurements made by [1], which included measurements of emissions from well completion flowbacks as well as measurements of emissions from chemical injection pumps, pneumatic devices, equipment leaks, and tanks at 150 NG production sites around the United States already in routine operation (measurements from tanks were not used for inventory purposes). However, the measurements of emissions at well production sites already in operation (which comprised 98% of the new inventory developed by [1]) were made using the Bacharach Hi-Flow Sampler (BHFS; Bacharach, Inc., New Kensington, PA) and recent work has shown that the BHFS can underreport individual emissions measurements by two orders of magnitude [10]. This anomaly occurs due to sensor transition failure that can prevent the sampler from properly measuring NG emission rates greater than ~0.4 standard cubic feet per minute (scfm; 1 scfm =  $1.70 \text{ m}^3 \text{ h}^{-1}$  or  $19.2 \text{ g min}^{-1}$  for pure CH<sub>4</sub> at 60°F [15.6°C] and 1 atm; these are the standard temperature and pressure used by the U.S. NG industry). Although this failure is not well understood, it does not seem to occur when measuring pure CH<sub>4</sub> streams, but has been observed in four different samplers when measuring NG streams with CH4 contents ranging from 66% to 95%. The sampler's firmwareversion and elapsed time since last calibration may also influence the occurrence of this problem [10, 18].

This paper presents an analysis of the UT [1] emissions measurements that were made with the BHFS, and shows that high emitters (>0.4 sofm [0.7  $\rm m^3~h^{-1}$ ]) were reported very rarely at sites with a low CH<sub>4</sub> content in the well-head gas (<91%), consistent with sensor transition failure. It also details testing of the exact BHFS instrument used in that study and shows the occurrence of this sensor failure at an NG production site with a wellhead composition of 91% CH<sub>4</sub> (the highest CH<sub>4</sub> concentration site available during testing). Finally, the downwind tracer ratio measurements made by [1] at a subset of their test sites are reexamined and indicate that the BHFS measurements made at sites with low wellhead CH<sub>4</sub> concentrations were too low by factors of three to five.

### **Evidence of BHFS Sensor Transition Failure in the UT Dataset**

The Allen et al. [1] UT dataset is unique due to the large number of BHFS measurements made across a wide geographic range, the variety of emissions sources

(equipment leaks, pneumatic devices, chemical injection pumps, and tanks) and the wide range of NG compositions (67.4–98.4%  ${\rm CH_4}$ ) that were sampled. As such, the UT study provides an important opportunity to evaluate the occurrence of sensor transition failure in the BHFS as well as the impact of this issue on emission rates and emissions factors based on measurements in other segments of the NG supply chain.

The BHFS uses a high flow rate of air and a loose enclosure to completely capture the NG-emitting from a source, with the emission rate calculated from the total flow rate of air and the resulting sample NG concentration, after the background NG concentration is subtracted. The sampler uses a catalytic oxidation sensor to measure sample concentrations from 0% to 5% NG in air, but must transition to a thermal conductivity sensor in order to accurately measure sample concentrations higher than 5%. It is the failure of the sampler to transition to the higher range that has been previously observed by Howard et al. [10] and which can prevent the sampler from correctly measuring emission rates larger than 0.3–0.5 scfm (0.5–0.9 m³ h<sup>-1</sup>) (corresponding to sampler flow rates of 6–10 scfm [10–17 m³ h<sup>-1</sup>]). Figure 1 summarizes data

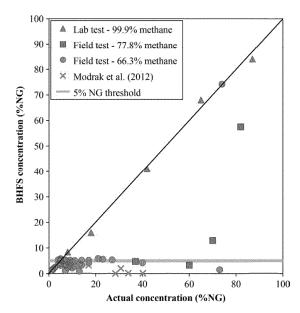


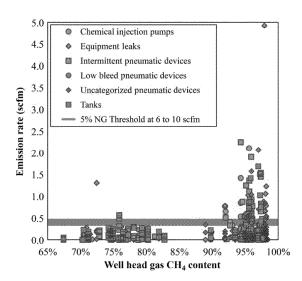
Figure 1. Occurrence of sensor transition failure in BHFS instruments with natural gas of varying CH<sub>4</sub> content from field and lab testing and from emission measurement studies (data from [10, 18]). NG concentrations in the BHFS sampling system measured by the BHFS internal sensor are compared to independent measurements of the sample NG concentrations. The 5% NG sample concentration threshold is the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity. BHFS, Bacharach Hi-Flow Sampler; NG, natural gas.

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showing the occurrence of sensor transition failure in several BHFS instruments during both fieldand laboratory testing as well as an example of the failure that occurred during an emission measurement study [10, 18].

Figure 2 presents the BHFS emission measurements from [1] as a function of percent  $CH_4$  in wellhead gas at each site. Figure 2 also shows a line corresponding to emission rates of 0.3–0.5 scfm (0.5–0.9  $\mathrm{m}^3$   $\mathrm{h}^{-1}$ ), which represents the range of emission rates that would require transition from the catalytic oxidation sensor to the thermal conductivity sensor at sample flows ranging from 6 to 10 scfm (10–17  $\mathrm{m}^3$   $\mathrm{h}^{-1}$ ).

As seen in Figure 2, there are very few measurements in the thermal conductivity sensor range (above  $\sim$ 0.4 scfm [0.7 m³ h^-1]) at sites where the wellhead gas composition of CH $_4$  is less than 91%, and this is true across all source categories. Raw data for sample flowand concentration from the BHFS were not provided in [1] supplemental information, so for this analysis, an average BHFS sample flowrate of 8 scfm (14 m  $^3$  h^-1) has been assumed, which is the lower of the two sampling flows specified by the Bacharach operating manual [4]. At this sample flowrate, an emission source of 0.4 scfm (0.7 m $^3$  h^-1) corresponds with a sample concentration of 5% NG in air, above



**Figure 2.** Emission rates of various sources measured by BHFS at NG production sites versus CH  $_4$  concentration of the wellhead gas (data from [1]). The solid line indicates the maximum emission rate that could be measured by the catalytic oxidation sensor only (i.e., in the case of sensor transition failure). For sites with a NG composition greater than 91% CH $_4$ , 13.3% of the measurements are in the TCD sensor range, assuming a sampler flow rate of 8 cubic feet per minute. For sites with less than 91% CH $_4$ , only 1.5% of the measurements are in the TCD range. BHFS, Bacharach HiFlow Sampler; NG, natural gas; TCD, thermal conductivity detector.

which point the sampler would need to transition to the thermal conductivity sensor to allow for accurate measurements. For sites with CH<sub>4</sub> concentrations less than 91%, only four out of 259 measurements (1.5%) exceeded 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>), while for sites with CH<sub>4</sub> concentrations greater than 91%, 68 out of 510 measurements (13.3%) exceeded 0.4 scfm  $(0.7 \text{ m}^3 \text{ h}^{-1})$ . Consequently, there were almost nine times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH $_4$  (Fig. 2). If the sample flow rate were 6 scfm (10 m $^3$  h $^{-1}$ ) (due to a flow restriction or reduced battery power), the threshold for transition to the thermal conductivity range would be 0.3 scfm (0.5 m<sup>3</sup> h<sup>-1</sup>); this would still mean that there were almost seven times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH<sub>4</sub> than at sites with >91% CH<sub>4</sub>. Although it is well known that a small percentage of NG emission sources account for most of the total emissions from any given population [9, 15, 25], it is unlikely that almost all the significant emitters at NG production sites would occur only at sites with well head gas compositions >91% CH, It is also unlikely that the emission rates of all of the source categories surveyed by [1], which had diverse emission mechanisms such as equipment leaks, pneumatic controllers, chemical injection pumps, and tanks, would all have a ceiling of ~0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) at sites with lower wellhead gas CH₄ concentrations. Consequently, the low occurrence of high emitters at sites with lower wellhead gas CH<sub>4</sub> concentrations in [1] indicates that sensor transition failure occurred at sites with CH<sub>4</sub> content <91% and is consistent with the BHFS sensor failure found by Howard et al. [10].

### Alternative Theories for the Emission Rate Pattern

Other possible causes of the emission rate pattern in the UT BHFS measurements were considered, including: regional operating differences at production sites; lighter gas densities resulting in higher emission rates; and improved detection of emissions by auditory, visual, and olfactory (AVO, e.g., [24]) methods at sites with heavier hydrocarbon concentrations.

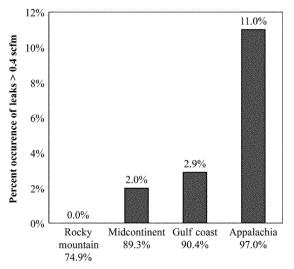
### Regional operating differences

Allen et al. [1] point out that air pollution regulations in Colorado which required installation of low bleed pneumatic devices in ozone nonattainment areas after 2009 might have led to lower emission rates in the Rocky Mountain region, which also had the lowest average concentration of  ${\rm CH_4}$  in the wellhead gas. However, if the

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Rocky Mountain region is removed from the analysis, the occurrence of emitters >0.4 scfm (0.7 m³ h^-1) at sites with wellhead gas <91% CH<sub>4</sub> was still only four out of 129 measurements (3.1%), while for sites with CH<sub>4</sub> concentrations greater than 91%, there remain 68 out of 510 measurements (13.3%) that exceeded 0.4 scfm (0.7 m³ h^-1) (there were no Rocky Mountain sites with CH<sub>4</sub> >91%). Consequently, even if the Rocky Mountain region is removed from consideration, the occurrence of emitters >0.4 scfm (0.7 m³ h^-1) was almost four times less at sites with less than 91% CH<sub>4</sub> than at sites with greater than 91% CH<sub>4</sub>, so air quality regulations in Colorado do not appear to be the cause of the emission rate trend shown in Figure 2.

Beyond air pollution regulations, other unknown regional operating practices unrelated to  ${\rm CH_4}$  concentration might coincidentally cause the apparent relationship of site  ${\rm CH_4}$  concentrations with the occurrence of high emitters. However, as shown in Figure 3, the increase in leaks >0.4 scfm  $(0.7~{\rm m^3~h^{-1}})$  directly correlates with the increase in the average regional  ${\rm CH_4}$  concentration. Because there are four regions and two variables (site  ${\rm CH_4}$  concentration and the percent of leaks >0.4 scfm  $[0.7~{\rm m^3~h^{-1}}]$ ), the likelihood that regional operating characteristics would coincidentally cause the increase in occurrence of leaks >0.4 scfm  $(0.7~{\rm m^3~h^{-1}})$  to mirror the increasing regional site  ${\rm CH_4}$  concentration is only one in 24 (four factorial), or ~4%.



Region and average wellhead CH<sub>4</sub> concentration

Figure 3. Occurrence of equipment leaks >0.4 scfm in each region of the [1] equipment leak data set. The odds of the occurrence of leaks >0.4 scfm being positively correlated with site CH <sub>4</sub> concentration are one in 24, which makes it unlikely this trend is due to regional operating effects.

Other known operating characteristics of the regions, such as average site pressure and average site age, are not related to the occurrence of equipment leaks >0.4 scfm (0.7 m $^3$  h $^{-1}$ ): average site pressures show no correlation, and average site age is negatively correlated with the occurrence of equipment leaks >0.4 scfm (0.7 m $^3$  h $^{-1}$ ).

Another argument against regional differences comes from the air quality study conducted by the City of Fort Worth ([6]; or the Ft. Worth study). Ft. Worth is part of the Mid-Continent region defined by [1], where the occurrence of equipment leaks only (as opposed to all BHFS measurement categories) >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) observed by [1] was 2.0% of the total equipment leaks in that region. However, equipment leaks >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) were 9.9% of the equipment leaks measured in the Ft. Worth study. This was determined using the Ft. Worth study categories of valves and connectors; their remaining category of "other", which included pneumatic control devices, had an even higher occurrence of sources >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) of 27.0%. Previous work [10] has shown that although sensor transition failure likely occurred in the Ft. Worth study, these incidents were limited compared to those in [1]. Consequently, the much lower occurrence of leaks >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) in the Mid-Continent region in [1] compared to the Ft. Worth study indicates that sensor transition failure was responsible for the low occurrence of emitters < 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) as opposed to regional differences.

### Gas density

Wellhead gas with a lower  $\mathrm{CH_4}$  and a greater heavier hydrocarbon content will be denser than gas with higher  $\mathrm{CH_4}$  content. Since gas flow through an opening is inversely related to the square root of the gas density, streams with lower  $\mathrm{CH_4}$  content would have a lower flow rate if all other conditions were the same. However, this would cause at most a 20% decrease for the lowest  $\mathrm{CH_4}$ /highest heavier hydrocarbon streams compared to the highest  $\mathrm{CH_4}$ /lowest heavier hydrocarbon streams observed in the UT study. This would also result in a gradual increase in emissions as  $\mathrm{CH_4}$  content increased, as opposed to the dramatic increase in emissions observed over a very narrow range of  $\mathrm{CH_4}$  concentrations (Fig. 2).

#### **AVO** detection

AVO methods might improve for gas streams with a greater proportion of heavier hydrocarbons, since those streams would have greater odor and might leave more visible residue near a leak. However, Figure 4 presents the occurrence of emitters >0.4 scfm (0.7 m $^3$  h $^{-1}$ ) as a function of site CH $_4$  concentrations in the Appalachia

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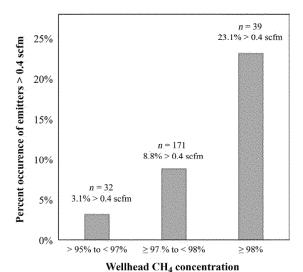


Figure 4. Occurrence of emitters >0.4 scfm as a function of site wellhead gas composition in [1] for the Appalachia region. An emission rate of greater than 0.4scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of 8scfm. The dramatic increase in emitters >0.4scfm over a narrow concentration range argues against the possibility that auditory, visual, and olfactory leak detection is the cause of the emission rate pattern seen in the [1] data set.

region alone. This region had the highest average CH<sub>4</sub> concentration in wellhead gas of any of the regions sampled in [1]. As seen in Figure 4, even over a very narrow range of site  $CH_4$  concentrations (from 95% to >98%  $CH_{A}$ ), there is a dramatic increase in emitters >0.4 scfm  $(0.7 \text{ m}^3 \text{ h}^{-1})$  with increasing CH<sub>4</sub> concentration. It is unlikely that AVO methods would become so much more efficient over such a narrow range of high CH 4 concentrations where the gas streams are likely odorless and would leave little residue. This dramatic increase in high emitters at sites with high CH<sub>4</sub> concentrations within the Appalachia region alone also argues against the previously discussed regional operating differences hypothesis in general, since this trend is within a single region. Additionally, although the Rocky Mountain region surveyed by UT [1] had the lowest average site CH<sub>4</sub> concentration (74.9%) and heaviest hydrocarbon content, it actually had the highest number of equipment leaks (of any size) per well of all the regions, and there were 25% more leaks per well in that region than in the Appalachia region, which had the highest average site CH<sub>4</sub> concentration (97.0%) and therefore the lowest heavier hydrocarbon content. If AVO methods were more effective due to the presence of heavier hydrocarbons, it seems unlikely the region with the heaviest hydrocarbon concentrations would have the highest rate of overall leak occurrences.

### Field Testing of the UT BHFS

Because the trend in the [1] data was consistent with sensor transition failure in the BHFS and no other explanation seemed plausible, I partnered with UT to test the sampler used by [1]. During that field program, the UT sampler had a version of firmware earlier than version 3.03, and older firmware versions have been shown to exhibit sensor transition failure [10]. However, the possible effect of the sampler's firmware version on the sensor failure was not known before this testing of the UT sampler, and at the time of my testing its firmware had been upgraded to a custom version (3.04).

As previously explained, the BHFS uses a catalytic oxidation sensor to measure sample stream concentrations from 0% to  $\sim\!5\%$  NG, and a thermal conductivity sensor for concentrations from  $\sim\!5\%$  to 100% NG. The catalytic oxidation sensor is typically calibrated with 2.5% CH $_4$  in air and the thermal conductivity sensor is calibrated with 100% CH $_4$  [4]. The manufacturer recommends sensor calibration every 30 days, a process which adjusts the response of the instrument. The calibration may also be checked ("bump-tested") periodically by the user, which does not adjust the instrument response. It is important to note that the description of the BHFS sensor operation in the supplemental information of [1] is incorrect, as they state that:

[A] portion of the sample is drawn from the manifold and directed to a combustibles sensor that measures the sample's methane concentration in the range of 0.05–100% gas by volume. The combustibles sensor consists of a catalytic oxidizer, designed to convert all sampled hydrocarbons to  $\rm CO_2$  and water. A thermal conductivity sensor is then used to determine  $\rm CO_2$  concentration.

However, the BHFS manual [4] clearly states that the catalytic oxidation sensor is used to measure concentrations from 0% to 5%  $\rm CH_4$  and the thermal conductivity sensor from 5% to 100%  $\rm CH_4$ . This is a critical distinction because understanding that the BHFS uses a different sensor for each range and that it must transition from the catalytic oxidation sensor to the thermal conductivity sensor in order to conduct accurate measurements is critical to understanding the problem of sensor transition failure.

I initially conducted field testing of the UT sampler in conjunction with the UT team at a NG production site with a wellhead gas CH<sub>4</sub> concentration of 90.8%. NG composition analysis (via gas chromatograph-flameionization detector) of wellhead gas at this site was conducted by the host company just prior to the sampler testing. The tests were conducted by metering known flow rates of NG into the BHFS inlets through a rotameter (King Instrument Company, Garden Grove, CA; 0–10 scfm air

scale). The sample concentration indicated by the internal BHFS sensor was recorded and compared to an external gas concentration monitor used to measure the actual NG concentration at the sampler exhaust (Bascom-Turner Gas Sentry CGA 201, Norwood, MA). The Gas Sentry unit was calibrated with 2.5% and 100%  ${\rm CH_4}$  prior to the testing; exhaust concentrations measured using this unit agreed with concentrations calculated using the sampler flowrate and amount of NG metered into the inlet to within an average of  $\pm 6\%$ .

This field testing was conducted in March of 2014 and is described by [10]; the UT sampler is identified therein as BHFS No. 3. At the time of this testing, the UT BHFS had firmwareVersion 3.04 (September 2013); this sampler had been calibrated 2 weeks prior to the fieldtest and had been used for emission measurements at production sites since that time. The response of the sensors was checked ("bump-tested") by the UT field team but not calibrated prior to the start of testing. This was apparently consistent with the UT fieldprogram methodology: the sampler had been used for measurements with only sensor bump tests, but without the actual calibration unless the sensors failed the bump tests (as was acceptable according to the manufacturer's guidelines) during their ongoing field measurement program and was provided to me for these measurements "ready for testing".

Although the UT sampler's internal sensors initially measured the sample concentration correctly, after ~20 min of testing the sampler's sensors failed to transition from the catalytic oxidation scale (<5% NG) to the thermal conductivity scale (>5% NG), resulting in sample concentration measurements that were 11-57 times lower than the actual sample concentration (Fig. 5). Because sample concentration is directly used to calculate emission measurements made by the sampler, this would result in emission measurements that are too low. After this sensor transition failure occurred, the UT BHFS was calibrated (not simply "bump-tested") and thereafter did not exhibit any further sensor transition failures even during a second day of testing at sites with wellhead CH<sub>4</sub> concentrations as low as 77%. Two other BHFS that were not part of the UT program were also tested using the same procedure: these instruments had the most updated firmware commercially available (Version 3.03) and were put through an actual calibration sequence by the instrument distributor's representative prior to any testing. Neither of these instruments exhibited sensor transition failure at any of the sites. These results combined with the sensor transition failure previously observed in instruments with earlier versions of firmware suggest that the combination of updated firmware and frequent actual calibrations might reduce sensor failure, although this has not been proved conclusively [10, 11].

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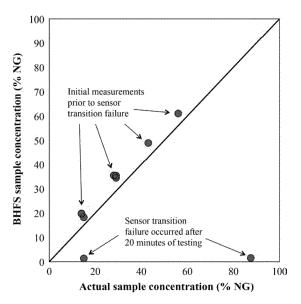


Figure 5. Performance of the BHFS used during the [1] study with NG composed of 90.8% CH<sub>4</sub>; instrument firmware had been upgraded to version 3.04 after that study but before this testing; calibration was 2 weeks old. Sensor transition failure set in after ~20min of testing; this failure was eliminated once the BHFS was put through a calibration sequence (as opposed to just a response test). BHFS, Bacharach HiFlow Sampler: NG, natural gas.

The UT recently published a follow-up study of pneumatic device emissions [2]. As part of this work, Allen et al. [2] conducted laboratory testing of the UT BHFS by making controlled releases of both 100% CH<sub>4</sub> and a test gas of 70.5% CH<sub>4</sub> mixed with heavier hydrocarbons into the UT BHFS and did not report any sensor transition failures during these tests, but during this laboratory testing the sampler (with the updated firmware version 3.04) was calibrated (not 'bump-tested") immediately prior to any testing. Consequently, the absence of sensor failure during their laboratory testing is consistent with the results observed during the March 2014 field tests, where calibrating the instrument eliminated the sensor failure.

Allen et al. [3] have suggested that the protocol during their field campaign was to check the calibration of the UT BHFS anytime it was turned on and that not following this protocol led to the sensor transition failure observed during this testing. However, in this instance, the sensor failure occurred both prior to and after the instrument was restarted. Additionally, the UT team observing the testing process did not suggest a calibration check when the instrument was turned back on for further testing. It was only after the sensor failure was observed that they checked and calibrated the instrument, so it

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does not appear that their protocol was to check the instrument calibration anytime it was turned on.

In summary, because the firmwarefor the UT sampler was updated prior to this testing (and therefore not the same as the version used during the UT field campaign [1]), and updated firmware may be a factor in reducing sensor failure, it is not expected that these test results are representative of how frequently sensor transition failure might have occurred during the UT study [1]. However, these results do clearly demonstrate that sensor transition failure could occur while using the UT BHFS.

### Comparison With Other Pneumatic Device Studies

Two other recent studies have measured emission rates from pneumatic devices by installing meters into the supply gas lines of the devices, as opposed to measuring emissions using the BHFS as was done by Allen et al. [1]. Prasino [22] used the meter installation technique to study emissions from pneumatic controllers in British Columbia, and the UT follow-up study [2] installed meters to measure emission rates from pneumatics in the four regions surveyed in the previous UT study [1].

Unfortunately, it is not possible to compare the pneumatic device emission factors from [1] to those from either the Prasino study, or from [2], because even though [1] sought to randomly sample pneumatic devices, the result was clearly an emitter data set (measurements focused on pneumatic devices that were emitting), while the Prasino data set was made with a random selection of devices and [2] made comprehensive measurements of all devices that could be measured safely at each site. This difference can be demonstrated by comparing the percentage of emitting intermittent pneumatic devices occurring in [1] to that in [2]. In [1], 95.3% (123 out of 129 intermittent devices) were greater than zero, with the smallest nonzero emitter equal to 0.12 scfh  $(0.0034 \text{ m}^3 \text{ h}^{-1})$ . In [2], only 57.5% (184 out of 320) intermittent devices) were greater than zero. This percentage of nonzero measurements drops further if the lowest nonzero emitter (0.12 scfh; 0.0034 m<sup>3</sup> h<sup>-1</sup>) observed by [1] is used as a threshold, in which case only 21.3% (68 out of 320) would be considered emitters. Since this threshold of 0.12 scfh (0.0034 m<sup>3</sup> h<sup>-1</sup>) is 25 times lower than the typical minimum range of the Fox FT2A meters by [2], the reported emitters below this threshold are most likely instrument noise caused by the meter's thermal elements inducing convection currents [7].

Consequently, although the intent of [1] was to survey randomly selected devices, their approach actually resulted in a data set comprised almost exclusively of emitting devices; this possibility is acknowledged by [2]. Therefore,

average emissions and emission factors for pneumatic devices calculated from [1] cannot be compared to those calculated from data collected by random or comprehensive sampling, such as presented in [22] or [2], because the emitter data set removes almost all the zero emitters and would result in much higher average emissions.

However, both [1] and [2] provide the  $\mathrm{CH_4}$  composition of the wellhead gas at the sites surveyed. This allows a comparison of emission rate patterns as a function of  $\mathrm{CH_4}$  concentration between devices measured by the BHFS [1] and by installed meters [2]. If the scarcity of high emitters measured by BHFS at sites with lower  $\mathrm{CH_4}$  concentrations in the initial UT study [1] was not an artifact caused by sensor transition failure, then the same concentration pattern should be present whether measured by the BHFS or by installed meters.

For this analysis, I removed the Rocky Mountain region to eliminate any bias from current or impending regulations that might have affected emission rates. Additionally, I focused on emissions from intermittent pneumatics because that provides the most complete data set from the two studies. Finally, as noted previously, the pneumatic device measurements from [1] apparently focused on emitting devices, whereas the devices surveyed in [2] were sampled as comprehensively as possible so the occurrences of high emitters in each study cannot be directly compared. Consequently, it is the ratio of the occurrences of high emitters at low CH<sub>4</sub> sites compared to high CH<sub>4</sub> sites within each study that must be compared.

As seen in Table 1, when measured by [1] via BHFS, the occurrence of emitters >0.4 scfm (0.7 m $^3$  h $^{-1}$ ) (on a percentage basis) at sites with wellhead gas compositions <91% CH $_4$  is almost a factor of five less than at sites with CH $_4$  >91%, consistent with BHFS sensor failure. Conversely, when measured via installed meters [2], the occurrence of emitters >0.4 scfm (0.7 m $^3$  h $^{-1}$ ) at sites with wellhead gas compositions <91% CH $_4$  is almost a factor of three higher than at sites with >91% CH $_4$ , indicating a complete reversal in this trend. This stark difference between BHFS measurements and installed meter measurements corroborates that the scarcity of high emitters at sites with lower wellhead gas CH $_4$  content present in [1] was an artifact due to sensor failure in the BHFS.

### Focused Analysis of the UT Study Equipment Leaks

In order to better understand the threshold of wellhead gas CH<sub>4</sub> concentrations at which sensor transition failure might occur, I conducted further analysis focused only on the equipment leak measurements in [1]. Equipment leaks were targeted because they are expected to be short term, steady state measurements, whereas emissions

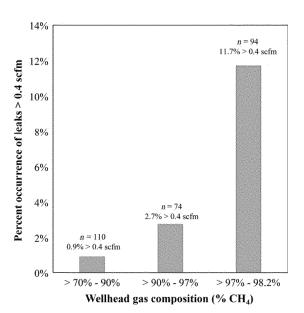
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Table 1. Occurrence of intermittent pneumatic device high emitters as a function of wellhead gas composition, measured by Bacharach Hi-Sampler (BHFS) and installed meters (Rocky Mountain region excluded).

	No. of devices measured	No. of devices with emissions >0.4 scfm	% of devices with emissions >0.4 scfm
Allen et al. [1] (Measured by BHFS sampler)			
Wellhead gas composition >91% CH₄	85	28	32.9
Wellhead gas composition <91% CH₄	44	3	6.8
Ratio of frequency of high emitters at sites with welll wellhead gas compositions >91 $\%$ CH $_{\!4}$	nead gas compositions <91% Ch	ન્ to sites with	0.21
Allen et al. [2] (Measured by installed meters)			
Wellhead gas composition >91% CH₄	106	3	2.8
Wellhead gas composition <91% CH <sub>4</sub>	97	8	8.2
Ratio of frequency of high emitters at sites with welll wellhead gas compositions >91% CH <sub>4</sub>	nead gas compositions <91% Ch	ન <sub>4</sub> to sites with	2.9

reported from pneumatic devices and chemical injection pumps are likely to be an average of several measurements, and emissions from tanks may have an NG composition different from the reported wellhead composition.

Figure 6 presents the occurrence of equipment leaks in [1] that are >0.4 scfm (0.7 m³ h $^{-1}$ ) as a function of site CH $_4$  concentrations. At sites with gas compositions of >97% CH $_4$ , 11.7% of the leaks were >0.4 scfm (0.7 m³ h $^{-1}$ ). At sites with wellhead compositions between 90% and 97% CH $_4$ , only 2.7% of the leaks were >0.4 scfm



**Figure 6.** Occurrence of equipment leaks >0.4scfm as a function of site well head gas CH <sub>4</sub> content in the [1] study. Leaks >0.4 scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of &cfm. The large increase in the occurrence of leaks >0.4 scfm at sites with CH<sub>4</sub> content >97% indicates sensor transition failure below that threshold.

(0.7 m³ h⁻¹), and this occurrence dropped to less than 1% at sites with wellhead gas compositions of <90% CH₄, indicating that the sampler's ability to measure leaks >0.4 scfm (0.7 m³ h⁻¹) declined dramatically with decreasing concentrations of CH₄ in the wellhead gas (Fig. 6). This analysis indicates the BHFS may underreport emitters >0.4 scfm (0.7 m³ h⁻¹) even when making measurements of NG streams with CH₄ content up to 97%, and provides a valuable refinement of the possible CH  $_4$  concentration threshold where sensor failure may occur, since the highest CH₄ wellhead content available for direct field testing of the BHFS was only 91.8%.

### Comparison of the UT Study Downwind Tracer Ratio Measurements to On-Site Measurements

Allen et al. [1] also made emission measurements using a downwind tracer ratio method at 19 sites for comparison to their on-site measurements. Their emissions from onsite measurements were calculated by using direct measurements of equipment leaks and pneumatic devices that were made by the UT team combined with estimates of emissions from any sources at the well pad that were not measured. These unmeasured sources included all tanks and compressors (compressors were a small source in comparison to all other sources) as well as any pneumatics that was not directly measured during the site survey. For CH<sub>4</sub> emissions from tanks and compressors, the authors used "standard emissions estimation methods" [1]. For pneumatic devices that were not surveyed, they applied their own emission factors based on the measurements of pneumatic devices collected during the UT study.

The tracer ratio measurements were made by releasing a tracer gas at a known rate to simulate the emissions from the site being measured. Simultaneous downwind measurements were then made of the concentrations of both the tracer gas and  $CH_4$ , and then the emission rate

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of  $\mathrm{CH_4}$  was calculated after correcting for background  $\mathrm{CH_4}$  and tracer concentrations. The tracer ratio method allows for the calculation of  $\mathrm{CH_4}$  emissions from the entire production site by accounting for the dilution of  $\mathrm{CH_4}$  as it is transported into the atmosphere from the source to the receptor.

In summarizing their tracer ratio measurements, [1] state: "For the production sites, emissions estimated based on the downwind measurements were also comparable to total on-site measurements; however, because the total on-site emissions were determined by using a combination of measurements and estimation methods, it is difficult to use downwind measurements to confirm the direct source measurements." However, upon further examination, I found that the downwind tracer measurements do in fact indicate the occurrence of sensor transition failure in their BHFS measurements.

Table 2 summarizes the characteristics of the sites surveyed by [1] using both the BHFS and the tracer ratio method. As described above, the on-site total is a combination of the measurements made by BHFS and estimates for any sources not actually measured by the UT team. I calculated the ratio of actual BHFS measurements to

the total reported on-site emissions (estimated and measured) using the supplemental information provided by [1]. Actual measured emissions ranged from 1% to 79% of the total reported on-site emissions and the on-site total emissions range from 13% to 3500% of the downwind tracer ratio measurements (Table 2).

Table 3 compares the tracer ratio measurements to the on-site emissions, categorized by  ${\rm CH_4}$  content in the well-head gas and by the fraction of actual BHFS measurements that comprise the on-site emissions. As shown in Table 3, when comparing all sites without separating them into these categories, the total of the tracer ratio measurements does agree closely to the on-site emissions, as [1] concluded. However, four of the sites had wellhead gas compositions of  $\geq 97\%$   ${\rm CH_4}$ , at which the BHFS would be expected to make accurate measurements. The remaining 15 sites had wellhead gas compositions of < 82%  ${\rm CH_4}$ , at which sensor transition failure might occur and the BHFS would underreport emissions measurements.

Once the sites are categorized by these wellhead gas compositions, a deficit between the on-site emissions and the tracer ratio measurements appears in sites with lower  $CH_A$  concentrations, and this deficit becomes more

Table 2. Sites surveyed by Allen et al. [1] using both Bacharach Hi-Flow Sampler (BHFS) and downwind tracer methods.

Tracer site	BHFS site	Wellhead gas CH <sub>4</sub> concentration	On-site total <sup>2</sup> (BHFS measurements and estimates)	BHFS measure- ments/on-site	Leaks measured by BHFS/on-site	Tracer ratio emission rate	On-site total/ tracer ratio
name <sup>1</sup>	name <sup>1</sup>	(%)	(scfm CH <sub>4</sub> )	total <sup>3</sup>	total <sup>3</sup>	(scfm CH <sub>4</sub> )	emission rate
MC-1	MC-1	70.9	1.89	0.12	0.12	2.32	0.815
MC-2	MC-14	78.1	0.99	0.34	0.01	2.00	0.495
MC-3	MC-20	77.2	1.63	0.45	0.18	2.95	0.552
MC-4	MC-5	74.2	2.31	0.19	0.14	3.36	0.687
MC-5	MC-16	79.3	1.85	0.56	0.18	4.16	0.445
RM-1	RM-7	81.9	0.22	0.11	0.09	0.584	0.368
RM-2	RM-8	74.5	4.43	0.02	0.02	1.70	2.60
RM-3	RM-1	76.4	0.13	0.67	0.69	0.442	0.303
RM-4	RM-3	74.9	0.11	0.21	0.00	0.839	0.137
RM-5	RM-2	74.5	0.09	0.35	0.33	0.240	0.392
RM-6	RM-5	74.5	0.74	0.41	0.42	0.421	1.75
RM-7	RM-14	74.5	0.27	0.26	0.26	0.368	0.736
RM-8	RM-19	76.2	0.29	0.82	0.79	1.08	0.266
RM-9	RM-12	74.5	0.38	0.05	0.05	0.864	0.436
RM-10	RM-4	76.2	2.86	0.01	0.00	0.080	35.7
AP-2	AP-23	97.6	1.28	0.68	0.35	0.270	4.74
AP-3	AP-43	97.0	4.75	0.62	0.59	4.12	1.15
AP-4	AP-37	97.0	1.36	0.44	0.42	0.709	1.92
AP-5	AP-18	97.0	0.39	0.74	0.69	0.288	1.37

<sup>&</sup>lt;sup>1</sup>MC, Midcontinent; RM, Rocky Mountain; AP, Appalachia. Different site numbers were used to identify the same sites in the [1] supplemental information depending on whether BHFS or tracer ratio measurements were under discussion.

<sup>&</sup>lt;sup>2</sup>On-site totals were calculated by [1] by combining measurements made by the BHFS with estimates of any sources not measured; these estimates were made using mathematical models for tanks as well as emission factors for compressors and any pneumatic controllers not directly measured. <sup>3</sup>Calculated by this author from [1] supplemental information.

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pronounced as the amount of the on-site emissions actually measured by the BHFS becomes a larger fraction of the total on-site emissions (measured and estimated). As seen in Table 3, for the high CH<sub>4</sub> sites where the sampler should function properly, the on-site measurements and estimates exceed the tracer measurements, but approach a ratio of one (complete agreement) as the amount of actual measurements increases. For the two sites with wellhead gas compositions ≥97% where the measured equipment leaks (which should produce steady emissions as compared to pneumatic devices which might be intermittent) averaged 64% of the total on-site measurements and estimates, the on-site total still exceeds the tracer measurements but are within 17% (Table 3). However, for the sites with wellhead gas  ${\rm CH_4}$  concentrations <82%, there is a clear trend of increasing deficit of the on-site emissions compared to the tracer ratio measurements as the actual BHFS measurements become a larger part of the on-site total. For instance, for the nine sites with at least 20% of on-site emissions from BHFS measurements (for an average of 45% of the total on-site emissions measured by the BHFS), the on-site emissions are only 49% of the tracer measurements (Table 3). For the two sites that had greater than 67% of on-site emissions data actually measured by the BHFS (for an average of 75% of on-site emissions data measured by the BHFS), the on-site emissions are only 28% of the tracer measurements (Table 3).

Comparing the on-site data to the downwind tracer measurements provides two valuable insights. First, there were six sites in the Rocky Mountain region for which at least 20% of the on-site emissions were measured by the BHFS (for an average of 45% actual BHFS measurements) (Table 2). For these six sites, the on-site emissions average 48% of the tracer data. For the two sites in this

region with at least 67% of on-site emissions from actual BHFS measurements (and with BHFS measurements averaging 75% of the total on-site data), the on-site emissions were only 28% of the tracer measurements (Table 2). This provides clear evidence that the sampler actually did fail in the Rocky Mountain region, as opposed to any possible regional differences (discussed previously) that might have created an emission pattern of no high emitters at sites with lower  ${\rm CH_4}$  concentrations in the wellhead gas.

Additionally, the tracer measurements provide a method to estimate the magnitude of errors introduced in the data collected by [1] due to BHFS sensor transition failure. For all of the sites with wellhead gas compositions ≥97% CH<sub>4</sub> (where the sampler should operate correctly), the emission rates determined by on-site measurements exceeded those determined by the downwind tracer ratio measurements. Assuming that the tracer method accurately measured the total emissions from the sites surveyed (e.g., [8, 15, 16]), I concluded that the methods used in [1] overestimated the on-site sources that were not directly measured. Therefore, I calculated the error in BHFS measurements at sites with low CH<sub>4</sub> wellhead gas composition by assuming the tracer ratio measurements are correct. I have also assumed for this analysis that the estimates of any onsite sources made by [1] are also correct, even though the tracer data indicate they may be too high, because this is conservative in the sense that correcting for this overestimate would increase the BHFS error calculated below. Given these assumptions, subtracting the on-site estimated emissions from the tracer ratio emissions gives the expected measurement total that should have been reported from the BHFS measurements. Comparing this expected measurement total to the actual

Table 3. Comparison of on-site measurements to tracer ratio measurements made by Allen et al. [1] categorized by wellhead gas CH<sub>4</sub> concentration.

Average percentage of on-site emissions reported by BHFS	Total on-site emissions (reported by BHFS and estimated) (scfm CH <sub>4</sub> )	Total emissions measured by tracer (scfm CH <sub>4</sub> )	Ratio of on-site emissions to emissions measured by tracer
37	26.0	26.8	0.97
to be accurate (wellhead	gas composition ≥97% CH	<u>(</u> )	
62	7.78	5.39	1.44
68	6.42	4.68	1.37
64 (equipment leaks/on-site total)	5.14	4.41	1.17
to underreport high emit	ters (wellhead gas composi	tion <82% CH <sub>2</sub> )	
28	18.2	21.4	0.85
35	10.9	19.6	0.56
45	6.10	12.5	0.49
69	2.27	5.68	0.40
75	0.42	1.52	0.28
	of on-site emissions reported by BHFS  37 to be accurate (wellhead 62 68 64 (equipment leaks/on-site total) to underreport high emit 28 35 45 69	of on-site emissions reported by BHFS and estimated) (scfm CH <sub>4</sub> )  37 26.0  to be accurate (wellhead gas composition ≥97% CH62 7.78  68 6.42  64 (equipment 5.14 leaks/on-site total)  to underreport high emitters (wellhead gas composition ≥28 18.2  35 10.9  45 6.10  69 2.27	of on-site emissions reported by BHFS and estimated) (scfm CH <sub>4</sub> ) tracer (scfm CH <sub>4</sub> )  37 26.0 26.8  to be accurate (wellhead gas composition ≥97 % CH <sub>4</sub> )  62 7.78 5.39  68 6.42 4.68  64 (equipment 5.14 4.41 leaks/on-site total)  to underreport high emitters (wellhead gas composition <82 % CH <sub>4</sub> )  28 18.2 21.4  35 10.9 19.6  45 6.10 12.5  69 2.27 5.68

BHFS, Bacharach Hi-Flow Sampler.

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measurement total reported by the BHFS provides an estimate of the error in BHFS measurements made by Allen et al. [1].

Table 4 presents the results of this analysis, and shows that for the 13 sites with wellhead gas compositions <82% CH<sub>4</sub> and with at least 5% actual BHFS measurements (with an average of 35% of emission sources measured by BHFS; bottom half of Table 3), the actual measurement total of the BHFS is less than one-third of the expected total, and this appears consistent as sites with greater fractions of actual BHFS measurements are examined. For these sites, the emission rates for equipment leaks and pneumatics devices presented by [1] are approximately equal, so it is not possible to assign a larger error to one category or another. Additionally, the errors introduced by the sensor failure would be expected to vary from site to site depending on how many emitters were present with emission rates exceeding the sensor transition threshold ceiling. Nevertheless, for these 13 sites, the BHFS underreported emissions for equipment leaks and pneumatic devices on average by more than a factor of 3 (Table 4).

Although the magnitude of error due to BHFS sensor failure is not known for all the sites in [1], the tracer ratio measurements make clear that the BHFS measurements for sites with lower CH<sub>4</sub> content in the wellhead gas could be at least a factor of three too low. More precise estimates of errors in [1] are not possible because of the nature of the sensor failure. Unlike a simple calibration error, for which it might be possible to correct, when sensor transition failure occurs, it is not possible to know for any particular measurement if the failure has occurred, and if it has, what the resulting error was, since the reported emission rates could range from 20% to two orders of magnitude too low.

### **Implications**

Sensor transition failure is clearly apparent in the BHFS measurements made in the UT study by Allen et al. [1], as evidenced by the rare occurrence of high emitters at sites with lower CH<sub>4</sub> (<91%) content in the wellhead gas. The occurrence of this sensor transition failure was corroborated by fieldtests of the UT BHFS during which it exhibited this sensor failure, as well as by tracer ratio measurements made by [1] at a subset of sites with lower wellhead gas CH4 concentrations. At this subset of sites, the tracer ratio measurements indicate that the BHFS measurements were too low by at least a factor of three. Because BHFS measurements were the basis of 98% of the inventory developed by [1] using their own measurements (and 41% of their total compiled inventory), the inventory clearly underestimates CH<sub>4</sub> emissions from production sites. However, the extent of this error is difficult to estimate because the underreporting of emission rates due to BHFS sensor transition failure at any given site would vary depending on sampler performance and on how many high emitters were present at that site. Estimating this error is further complicated by the fact that the data set collected for pneumatic devices by [1] was an emitter data set; this might offset the effect of underreported high emitters in their pneumatic device emission factors. Finally, although real differences may exist in regional emission rates, the UT data set [1] should not be used to characterize them because the occurrence of sensor failure clearly varied between regions due to variations in wellhead CH₄ compositions, which may mask any actual regional differences that existed.

Although the performance of the BHFS may vary between instruments or with sensor age or calibration vintage, this analysis of the [1] data set shows that measurements made using a BHFS for NG streams with  ${\rm CH_4}$  content

**Table 4.** Estimation of underreporting in Allen et al. [1] BHFS measurements of CH<sub>4</sub> emission rates at sites with low CH<sub>4</sub> well head gas composition (<82%), using downwind tracer measurements (from Table 3).

Minimum percentage of on-site emissions reported by BHFS	Average percentage of on-site emissions reported by BHFS	No. of sites	Total emissions measured by tracer (scfm CH <sub>4</sub> )	On-site emissions estimated by UT (excludes BHFS measure- ments) (scfm CH <sub>4</sub> )	Expected BHFS measurement total (tracer – on-site estimates) (scfm CH <sub>4</sub> )	Emissions reported by BHFS (sofm CH <sub>4</sub> )	Ratio of reported BHFS to expected BHFS
≥5	35	13	19.63	7.09	12.54	3.81	0.30
≥20	45	9	12.50	3.34	9.16	2.76	0.30
>50	69	3	5.68	0.71	4.97	1.56	0.31
>67	75	2	1.52	0.11	1.42	0.31	0.22

BHFS, Bacharach Hi-Flow Sampler; UT, University of Texas.

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up to 97% could lead to severe underreporting of NG leaks. That this failure can occur at such high  $\mathrm{CH_4}$  concentrations, which are close to the higher end of those found in transmission and distribution systems, indicates that past measurements in all segments of the NG supply chain could have been affected by this problem. Because the BHFS sensor transition failure phenomenon is not fully understood, it is not known how much this error may have affected past measurements of  $\mathrm{CH_4}$  emission rates. Two factors preclude this: first, the performance of any individual BHFS may vary, and second, once sensor transition failure occurs, there is no way to determine the magnitude of the measurement error in the absence of an independent flux or concentration measurement.

If BHFS sensor transition failure has occurred during industry monitoring at transmission, storage, and processing compressor stations where the BHFS is approved for leak measurements mandated by the USEPA Subpart W Greenhouse Gas Reporting Program (GHGRP) [23], then these errors could be larger than those observed at production sites. Leaks at transmission, storage, and processing compressor stations commonly exceed 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) (the approximate threshold for BHFS sensor transition failure) and in some cases may range from 10 to over 100 scfm. Because the largest 10% of leaks typically account for 60-85% of the total leak rate at a given facility [9, 25], sensor transition failure in the BHFS could bias CH4 emission inventories compiled by the USEPA GHGRP substantially low since the most significant leaks could be underreported. Additionally, leak measurements using the BHFS may be used to guide repair decisions at NG facilities, and underreporting of leaks could compromise safety if large leaks remain unrepaired as a result.

Finally, it is important to note that the BHFS sensor failure in the UT study [1] went undetected in spite of the clear artifact that it created in the emission rate trend as a function of wellhead gas CH<sub>4</sub> content and even though the authors' own secondary measurements made by the downwind tracer ratio technique confirmed the BHFS sensor failure. That such an obvious problem could escape notice in this high profile, landmark study highlights the need for increased vigilance in all aspects of quality assurance for all CH<sub>4</sub> emission rate measurement programs.

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### **Conflict of Interest**

The author is the developer of high flowsampling technology (US Patent RE37, 403) and holds a license to use it for any purpose; however, he does not sell high flow samplers nor was he involved in the development of the Bacharach Hi-Flow Sampler.

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## **Understanding Direct Emission Measurement Approaches for Upstream Oil and Gas Production Operations**

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### Mark T. Modrak and M. Shahrooz Amin

ARCADIS Inc., 4915 Prospectus Drive, Suite F, Research Triangle Park, NC 27713, USA

### J. Ibanez, C. Lehmann, B. Harris, and D. Ranum

Sage Environmental Consulting, 720 West Arapaho Road, Richardson, Texas 75080, USA

### Eben D. Thoma and Bill C. Squier

U.S. EPA, Office of Research and Development, National Risk Management Research Laboratory, 109 TW Alexander Drive, E343-02, Research Triangle Park, NC 27711, USA

### INTRODUCTION

Breakthroughs in oil and gas extraction technologies are leading to greatly increased production activity in many areas of the United States (U.S.). Environmentally responsible development of this critical asset requires an understanding of the potential impacts of air pollutant emissions from upstream oil and gas production sites. These emissions can include volatile organic compounds (VOCs), which may impact regional ozone levels, hazardous air pollutants (HAPs) that could potentially create air quality concerns for near-site residents, and greenhouse gases (GHGs) such as methane (CH<sub>4</sub>), a potent radiative forcing agent. A key to understanding emissions and mitigation options is in the development and optimization of cost-effective measurement methods specific to the upstream oil and gas production. Better measurements and models not only help protect the environment, but also help facilitate efficient resource development by alleviating concerns where appropriate.

Air emissions from oil and gas production sites vary based on a number of factors including the geologically-determined composition of the oil and gas product (wet or dry gas), age of well, production equipment designs, and equipment maintenance states. The U.S. EPA's mandatory GHG reporting rule will greatly increase knowledge of GHG emissions from oil and gas production operations, but there is an ongoing need to improve emissions estimates, as well as to facilitate identification and remediation of compliance issues related to air quality. To improve both the measurement methods and emissions knowledge for this sector, the U.S. EPA Office of Research and Development (ORD), and its partners are investigating both on-site direct and off-site remote measurement approaches.<sup>2</sup>

This extended abstract describes a direct measurement study of production pad emissions in the Greeley, CO area conducted by ARCADIS in coordination with Sage Environmental Consulting (Sage) and in collaboration with several industry operators. The study focused on determination of instantaneous VOC and CH<sub>4</sub> emissions from production pads (with emphasis on oil/condensate tank emissions) using non-invasive measurement techniques. In addition to preliminary emissions results, this abstract describes the instrumentation used and issues encountered in the study.

### BACKGROUND

In conjunction with a July 2011, EPA mobile measurement campaign in Weld County CO,<sup>2</sup> ARCADIS contracted Sage to perform on-site emission surveys at 23 oil and gas production pads in the area using previously demonstrated direct measurement and infrared camera

techniques.<sup>3</sup> The measurements were conducted in collaboration with three oil and gas companies that provided site access, process information, engineering descriptions, and safety oversight. The specific locations surveyed during the field study were determined prior to field deployment and were chosen to represent the range of operations (e.g. different gas qualities, condensate or produced water generation, etc.) present in the area and to maximize data collection efficiency. The identities of the companies and sites will remain anonymous for reporting purposes.

Emissions from production pads can be fugitive or vented in origin and for the purposes of this study, are grouped into four categories, tank emissions (three types) and non-tank emissions from auxiliary equipment (all other production pad emissions). As evidenced in recent measurement studies,<sup>2,3</sup> the most readily identified emission points by infrared camera observation are storage tank-related (i.e. leaking thief hatches). Atmospheric storage tank emissions (both oil/condensate and produced water) can be described as (1) tank breathing losses, that occur due to vapors produced by diurnal temperature changes, (2) tank working losses, that are caused by displacement during tank filling cycles, and (3) tank flashing losses, that occur when liquids with entrained gas experience a pressure drop during transfer of the liquid from a wellhead or separator. Of these four production pad emission categories (three tank and non-tank auxiliary), tank flashing losses are generally thought to be much larger than the others on an instantaneous basis. For this study, measurements from three of the four defined emission categories make up part of the data set (no tank working losses were observed). Emission measurements presented here represent "snapshots" in time. Because many production pad emissions (e.g. condensate tank flashing emissions) are short-term in nature, instantaneous emission measurements should not be extrapolated to tons per year values.

The air pollutant emissions from storage tanks can be mitigated in part by control devices, such as venting to flares, a technique typically employed in the Greeley, CO area. Although engineering calculations exist for estimation of tank emissions, <sup>6,7</sup> the effectiveness of controls due to engineering design variability, such as combustor back pressure, and maintenance-related variables such as thief hatch seal integrity, lead to uncertainty in actual emissions in comparison to estimates. Ideally a non-invasive, easy to execute quantification techniques could be used to produce reliable short-term emission measurements from these systems in order to increase emissions knowledge and compare actual emission to estimates.

The general goals for the study were to improve understanding component-level emissions and speciation profiles from production pads in the study area using non-invasive measurement approaches, such as infrared video and real-time leak measurements coupled with subsequent laboratory analysis of acquired canisters. Another goal of the study was to improve understanding of the performance of high volume sampling equipment<sup>6,7</sup> for emissions that are VOC rich (defined here as combustible vapor < ~95% CH<sub>4</sub>). A final goal was to improve understanding of non-invasive measurement techniques for study of condensate tank flash emissions. Other studies<sup>4,5</sup> investigating flash emissions have performed measurements using installed vent flow meters and with techniques to seal leaks so as to force all flow through the measurement location. This study investigates the utility of a less invasive approach to investigate flash emissions using a high volume sampler described below. Because flash emissions occur at irregular intervals and are not sustained, they are challenging for short duration direct measurement approaches. To help address this issue, the site operators manually induced flashing events, when deemed safe by the site operator and study personnel.

### **Experimental Methods**

The production pad infrared (IR) video survey and emission measurement procedures are discussed briefly here and will be detailed in a future EPA report. The methods are nearly identical to those used by Sage in execution of the site measurements portion of the City of Fort Worth Natural Gas Study. For each well pad, a pre-measurement site survey was conducted that included collection of GPS and meteorological data, generation of a detailed inventory of all major on-site equipment, creation of a site sketch showing the location of all major components, and collection of several photographs of the site. After the pre-measurement data was recorded, a leak inspection survey of the site was conducted using a model GasFinderIR® video camera (FLIR Inc, Billerica, MA, USA). When an emission point was identified, the camera operator documented the type of equipment that was emitting and the location of the leak or vented emission and the video was saved.

Following the IR camera survey, a Bacharach Hi Flow Sampler<sup>TM</sup> (BHFS, Bacharach Inc. New Kensington, PA, USA) was used to determine the emissions rate from all safely accessible emission points identified by the survey (Figure 1). The BHFS is designed for measuring CH<sub>4</sub> leaks in downstream natural gas inspection and maintenance applications (in natural gas processing plants for example), but less is known about its use in upstream measurement applications on gas streams that can possess significant non-CH<sub>4</sub> components. The following description of the BHFS design and operation is based on the best information available at the time of publication.<sup>8</sup> The BHFS consists of an intrinsically safe, induced flow (blower) sampling system that pulls a certain volume of the emitted gas and surrounding air through a flexible hose into a manifold for analysis. The sample first passes through a flow restrictor where a pressure differential is measured and used to calculate the flow rate of the sample-air mixture. The BHFS

automatically corrects the flow rates for difference in the density of air and CH<sub>4</sub>. A portion of the sample is diverted to a combustibles sensor based on a dual mode catalytic oxidation/ thermal conductivity pellistor (e2v technologies ltd. Chelmsford, Essex, United Kingdom) to determine measured gas concentrations. A similar sensor is also used to determine the background combustibles concentration. In automatic mode, the sampler lowers the induced flow to 80% of the initial value and compares the calculated leak rate to provide confidence that the leak was captured in its entirety. Care is taken that the exhaust of the sampler does not impact the background sensor.

Figure 1: Example of a condensate tank vent measurement with a BHFS.



In this study, for low emission rates where vapor concentrations were below the detection limit of the BHFS, the concentration was determined with a Thermo Toxic Vapor Analyzer 1000B (Thermo Scientific, Franklin, MA, USA). For large emissions exceeding the BHFS's upper flow

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range of 10.5 cfm, a bagging measurement was conducted using a three (3) standard cubic feet, anti-static measurement bag placed over the emission source (if conditions were deemed safe and the source was accessible) and its fill time was recorded.

For the BHFS measurements, the instrument-determined emission rate is calculated using Equation 1:

$$Emission (cfm) = \underline{Emission \% - Background \%} * Flow (cfm)$$

$$100$$
(1)

Where:

Emission (cfm) = Flow rate of emission in cubic feet per minute

Emission % = Volume percent of combustibles in the sample stream

Background % = Volume percent of combustibles in the background sampling area Flow (cfm) = Flow rate of sample and background air in cubic feet per minute

The BHFS response is calibrated at 2.5% and 100% CH<sub>4</sub> before each day's trials. As detailed in the results and discussion section, the translation of the BHFS from downstream natural gas inspection applications (where CH<sub>4</sub> dominates the emission speciation profile) to upstream applications on VOC-rich streams is not straightforward and the instrument-determined emission rate is now believed to deviate significantly from actual values under certain conditions.

In addition to BHFS readings, evacuated canister samples were collected at a select number of detected emission points at each site. Data from the canister samples in conjunction with the BHFS total flow results were used to compare with the volumetric emissions rate determined by the BHFS alone and also to estimate the mass emission rates of individual organic compounds from selected emission points. The samples were collected directly from the exhaust port of the BHFS during sampling, using a 6 liter SUMMA canister. The sample collection integration time was approximately 30 seconds. Canisters were generally collected at the largest emission point at each site, determined by the BHFS emission flow rate (cfm). A total of 33 canisters were acquired at the 23 sites. At least one canister was acquired at each site. The number of canisters at each site was dependent on and the amount and severity of emission points detected. The canisters were analyzed for the US EPA Photochemical Assessment Monitoring Stations (PAMS) Target Volatile Organic Compounds (VOC), as well as percent level CH<sub>4</sub>, ethane, ethene, propene, and propane by ASTM D1946/D1945.

Calculation of a emission rate of total combustibles (all canister-measured compounds) or total VOCs (all compounds excluding  $CH_4$  and ethane) using canister information was accomplished by summing the concentrations of individual measured species to achieve a total measured pollutant volume percent which was then multiplied by the total BHFS gas flow rate (converted to standard conditions). This canister-based emission rate is a modified version of Eq. (1) where the pollutant concentration is determined by the canister instead of the BHFS combustibles sensor.

Calculation of speciated mass emissions from the canister data was accomplished by first converting the VOC concentration results from ppmv to units of mg/m³, and converting the BHFS gas flow rate to standard gas flow. The VOC emission rate is calculated using Equation 2:

$$ER = C * CFMstd * CF * 8760$$
 (2)

Where:

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ER = VOC Emission Rate (lb/year)

C = VOC Concentration (mg/m³)

CFMstd = Flow rate (ft³/min) corrected to standard conditions

CF = Units Conversion Factor = 3.75 E-06 (1 m³/35.32147 ft³) *60 minutes/hour

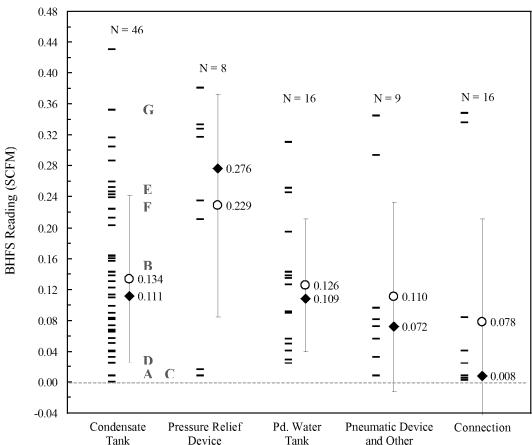
* (1 lb/453592.37 mg)
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Field data were collected electronically on data loggers and archived daily at the end of testing. Further information on procedures is contained in references 3 and 6.

### **Results and Discussion**

A total of 23 sites were surveyed, excluding two replicate site visits. The average production pad consisted of five wells, 258 valves, 2,583 connectors, three condensate tanks, one produced water tank, four thief hatches, five pressure relief devices, three separators, and all sites contained one flare/combustor. One production pad contained a dehydration unit, and four each contained one vapor recovery unit. Reference 6 contains engineering details of each production

Figure 2: BHFS volumetric emission rate readings by component group: (-) individual readings, (o) mean, (") median, bars represent ± 1s. Inset labels (A-G), see Figure 3.



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pad visited along with a layout sketch of each site. Of the 23 sites surveyed, 19 processed field gas by a single stage three phase separator and four utilized a two stage separation process to further recover natural gas by reducing the net pressure by approximately one fourth of the liquid sent to the condensate tanks via a buffer tank.

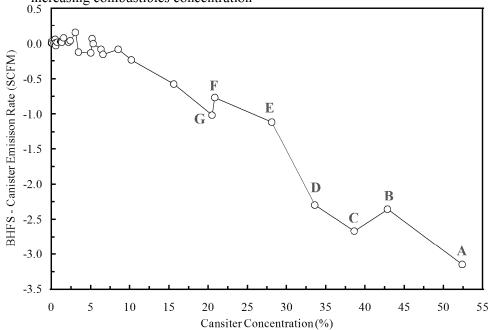
Each emission that was detected with the IR camera (93 total) was measured with the BHFS to determine the BHFS volumetric leak rate of the mixed vapor stream. The average emission rate determination for five major component grouping is shown in Figure 2. Condensate tank emissions were identified as leaking thief hatches (N=44) and vent structure (N=2). All measurements in the pressure relief device category came from condensate tank emissions. Thirteen of the produced water tank measurements were from vents with two described as hatches and one as a cover. Emissions from five pneumatic control devices were measured with "other" category consisting of one valve, two equipment vent devices. The remaining two measured emissions in this category came from a vapor recovery unit knock-out pot (0.34) SCFM) and a leaking compressor filter (0.294 SCFM). The final category represents all miscellaneous connections and fittings observed to be leaking. As similarly observed in other studies, 2,3 leaking thief hatch seals on condensate tanks was the most frequently observed production pad emission category. The difficulty in maintaining seal integrity is readily acknowledged by industry collaborators for this study. Additional details on emissions from various component types with associated IR video examples will be included in the presentation. The inset labels in Figure 2 (labels A-G), associated with the condensate tank emissions, are present to reference specific measurements described in Figure 3.

As discussed in the experimental methods section, the BHFS is calibrated to CH<sub>4</sub> and the volumetric emission determination is believed to be relatively accurate for measurement of emissions within its operational range that are primarily composed of CH<sub>4</sub> (i.e. combustibles > ~95% CH<sub>4</sub>). Emissions from well pads in Weld County Colorado have high VOC to CH<sub>4</sub> ratios due to the wet gas nature of the production in this area (in contrast to Fort Worth, TX).<sup>3</sup> This difference is particularly exaggerated for this study since a large percentage of the measurements came from condensate tank emissions. It is hypothesized that because the BHFS utilizes a dual mode catalytic oxidation/ thermal conductivity sensor to determine combustible gas concentrations, measurements of sample stream gases with different physical properties than CH<sub>4</sub> will affect various aspects of the operation of the BHFS. The primary effect is found to be in the vapor concentration determination used in Eq 1. Flow rate bias due to density differences of the sample stream relative to CH<sub>4</sub> are also likely present but are not discussed here.

As determined by canister analysis (discussed subsequently), the typical hydrocarbon profile varies by source (i.e. condensate tank compared to non-tank) but is dominated by aggregate non-CH<sub>4</sub> species (ethane, propane, butane, etc) for this study (in contrast to profiles from dry gas fields).<sup>3</sup> For this study, when sampled combustibles concentrations exceed ~ 10%, (caused by low dilution through the BHFS), the BFHS determined volumetric emission readings can be biased low (Figure 3). The ordinate of Figure 3 shows the difference in the BHFS determined volumetric emission rate (called BHFS) and that found by combining the canister-derived total combustibles concentration with the BHFS total flow rate (called canister), plotted against the total combustibles percent by volume in the canister (abscissa). At up to » 5% combustible concentration by volume, the BHFS's sensor is believed to operate in catalytic oxidation mode then, as the concentration increases, the oxidation is saturated and the sensor switches to thermal conductivity mode. The unit's response is calibrated at 2.5% (mid range of the catalytic

oxidation mode) and 100% CH<sub>4</sub> before each day's trials. Since the relative thermal conductivity of CH<sub>4</sub> compared to air is significantly higher than that of other observed hydrocarbons (at the pellistor's operating range around 500 C), the concentration reading (and hence leak rate

Figure 3: Difference in BHFS and canister-determined emission rates with increasing combustibles concentration



determination) of the BHFS underestimates actual by progressively larger amounts with increasing total concentration of non-CH<sub>4</sub> combustibles. This situation occurs for larger leaks but is also affected by the coupling of the extraction system which controls the dilution of the vapor stream.

The underestimation of the volumetric emission rate in these cases can be very significant as evidenced by the inset labels (A-G) of Figure 3 that link the largest absolute difference measures (BHFS - Canister results) to the BHFS determined values shown in Figure 2. It is the case that among the lowest measured values with the BHFS were some of the highest actual emissions. In fact, cases A, C, and D, were condensate flash emission events, which are known to greatly exceed breathing emissions on a short time duration basis. It is believed that this underestimation in the volumetric emission response of the BHFS is due mostly to the aforementioned concentration determination issues caused by the thermal conductivity differences found in VOC-rich streams, but may also be due in part to internal flow rate density compensation issues that arise from non-CH<sub>4</sub> emissions. These factors are the subject of further investigation. Regardless of cause, this low bias can be reduced through additional dilution of the sampling stream (increasing clean air flow). This would however further limit the useful range of the instrument (currently 10.5 CFM maximum total flow rate) so alternative measures, such as calibrated leak bagging, become more attractive.<sup>6,7</sup>

Methane and VOC mass emission rate estimates were produced for a subset of observed leaks (N=33) using the previously described procedure which combines the BHFS total flow and

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canister analysis (Figure 4). The VOC emission values represent the summation of 55 canister measured compounds that were above detection limit (excludes ethane and methane). All measurements were either associated with a condensate tank emissions or one of five non-tank related emissions sampled (two separator, two well head and one dehydrator). The speciation profiles for the tank and non-tank emissions were very different. A measure is found by calculating the volumetric ratio of CH<sub>4</sub> to the summation of other measured compounds (VOCs plus ethane) which yields values 243.3% (s = 161.3%) and 38.3% (s = 26.8%) for non-tank and tank related emissions respectively. It is noted that one produced water tank is included in the tanks set which possessed amongst the lowest CH<sub>4</sub> ratios (17.2%). Twenty five of the tankrelated canisters were acquired during thief hatch measurements with three from pressure relief or vent devices. The latter subset showed an average  $CH_4$  ratio of 20.3% (s = 6.8%). The  $CH_4$ ratio difference between the tank-related and non-tank related emissions is evident in Figure 4b which shows very low non-tank related VOC emissions. Five tank canisters were identified as being acquired during flash emissions and these samples showed CH4 to VOC ratios similar to the full set (39.6%, s = 35.1%). VOC emission measurements associated with these five flash canisters were (2.31 g/s, 1.59 g/s, 1.50 g/s, 0.20 g/s, and 0.02 g/s). The last of these values is believed to be unrealistically low and is the subject of further investigation. Data at this point is considered preliminary and is subject to revision.

#### **SUMMARY**

Improved understanding of both air pollutant emissions from oil and gas production operations and accuracy of the tools we use to measure and model these emissions is important for environmentally responsible development of this national asset. This extended abstract presents preliminary information from a direct measurement study of production pad emissions near Greeley, CO, conducted by ARCADIS in coordination with Sage Environmental Consulting and in collaboration with several industry operators. The goals of the study were to improve understanding of component-level emissions, speciation profiles, non-invasive measurement approaches, and condensate tank flash emissions. In addition to preliminary emissions results, this abstract describes the instrumentation used for data collection and methods used for emissions quantification. Next steps include continued processing of this data set to better understand instrument performance, measurement uncertainty, and source emissions. Additionally, recommendations for next steps in laboratory studies, field testing, and method development activities for sector specific non-invasive measurement approaches will be formulated.

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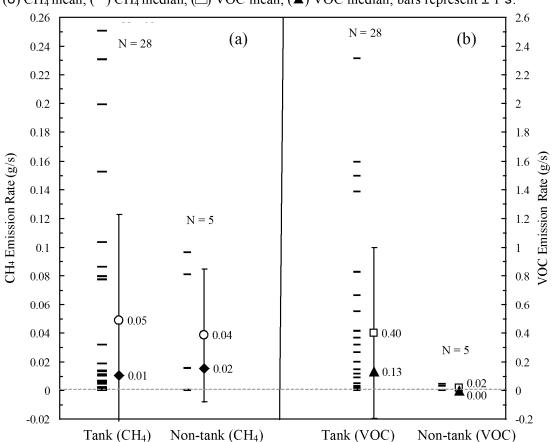


Figure 4: (a) CH<sub>4</sub> and (b)VOC Mass emission rate by canister calculation: (-) individual readings, (o) CH<sub>4</sub> mean, ( $^{\circ}$ ) CH<sub>4</sub> median, ( $^{\circ}$ ) VOC mean, ( $^{\diamond}$ ) VOC median, bars represent  $\pm 1$  S.

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- 8. Descriptions of the Bacharach Hi Flow Sampler<sup>TM</sup> design and operation limits are based on best available information including discussions with the manufacturer and the distributor of the instrument. This abstract is being communicated to the distributor and manufacturer and any corrections will be noted in presentation and full EPA report. Any misrepresentation is unintentional.

#### KEYWORDS

oil and gas production, fugitive emission, direct measurements, methane, VOC, HAP, GHG,



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# Assessment of volatile organic compound and hazardous air pollutant emissions from oil and natural gas well pads using mobile remote and onsite direct measurements

Halley L. Brantley, Eben D. Thoma & Adam P. Eisele

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#### TECHNICAL PAPER

# Assessment of volatile organic compound and hazardous air pollutant emissions from oil and natural gas well pads using mobile remote and on-site direct measurements

Halley L. Brantley, <sup>1</sup> Eben D. Thoma, <sup>2,/</sup> and Adam P. Eisele<sup>3</sup>
<sup>1</sup>Oak Ridge Institute of Science and Education Fellowship, U.S. Environmental Protection Agency, Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC, USA

 $^2$ U.S. Environmental Protection Agency, Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC, USA

<sup>3</sup>U.S. Environmental Protection Agency Region 8, Denver, CO, USA

Please address correspondence to: Eben D. Thoma, National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711, USA; e-mail: thoma.eben@epa.gov

Emissions of volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) from oil and natural gas production were investigated using direct measurements of component-level emissions on pads in the Denver-Julesburg (DJ) Basin and remote measurements of production pad-level emissions in the Barnett, DJ, and Pinedale basins. Results from the 2011 DJ on-site study indicate that emissions from condensate storage tanks are highly variable and can be an important source of VOCs and HAPs, even when control measures are present. Comparison of the measured condensate tank emissions with potentially emitted concentrations modeled using E&P TANKS (American Petroleum Institute [API] Publication 4697) suggested that some of the tanks were likely effectively controlled (emissions less than 95% of potential), whereas others were not. Results also indicate that the use of a commercial high-volume sampler (HVS) without corresponding canister measurements may result in severe underestimates of emissions from condensate tanks. Instantaneous VOC and HAP emissions measured on-site on controlled systems in the DJ Basin were significantly higher than VOC and HAP emission results from the study conducted by Eastern Research Group (ERG) for the City of Fort Worth (2011) using the same method in the Barnett on pads with low or no condensate production. The measured VOC emissions were either lower or not significantly different from the results of studies of uncontrolled emissions from condensate tanks measured by routing all emissions through a single port monitored by a flow measurement device for 24 hr. VOC and HAP concentrations measured remotely using the U.S. Environmental Protection Agency (EPA) Other Test Method (OTM) 33A in the DJ Basin were not significantly different from the on-site measurements, although significant differences between basins were observed.

Implications: VOC and HAP emissions from upstream production operations are important due to their potential impact on regional ozone levels and proximate populations. This study provides information on the sources and variability of VOC and HAP emissions from production pads as well as a comparison between different measurement techniques and laboratory analysis protocols. On-site and remote measurements of VOC and HAP emissions from oil and gas production pads indicate that measurable emissions can occur despite the presence of control measures, often as a result of leaking thief hatch seals on condensate tanks. Furthermore, results from the remote measurement method OTM 33A indicate that it can be used effectively as an inspection technique for identifying oil and gas well pads with large fugitive emissions.

#### Introduction

With revolutionary advancements in oil and natural gas extraction capability comes enhanced responsibility understand air pollutant emissions associated with this growing sector (U.S.Environmental Protection Agency [EPA], 2013c). Environmentally responsible development requires accurate knowledge of methane (CH<sub>4</sub>) emissions from all parts of the supply chain (Moore et al., 2014; Caulton et al., 2014; Howarth

et al., 2011) as well as an understanding of overall air impacts from relatively short-lived well site creation, drilling, and completion, and the long-term production operations (Allen et al., 2013; EPA, 2007; McKenzie et al., 2012). To support low-environmentalimpact ongoing field operations, an understanding of emissions and mitigation approaches for upstream oil and natural gas production sites (well pads) is required (EPA, 2013c). In addition to CH<sub>4</sub>, well pad emissions can include volatile organic compounds

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(VOCs), which may impact regional ozone levels (Rodriguez et al., 2009; Kemball-Cook & 2021(2); Schnell et al., 2009; Pétron et al. 2014; EPA, 2014; Thoma et al., 2012; Eapi et al., 2014). 2012), and hazardous air pollutants (HAPs) that could potentially create air quality concerns for near-site residents (Zielinska et al., 2014: Colorado Department of Public Health & Environment [CDPHE], 2007; Walther, 2011). Well pad emission profiles vary based on the geologically determined composition of the product, age of the well, production equipment design, and maintenance states of systems and emission control devices. Well pad emissions can be difficult to measure and model due to the large number of potential sources (vented and fugitive), including temporally variable emissions from condensate storage tanks with and without emission controls (Field et al., 2014; Brandt et al., 2014; Hendler et al., 2006; Gidney and Pena, 2009; Allen et al., 2013). Other common production pad components with associated combustion emissions such as separator burners, enclosed combustion devices (ECDs), and engines were not included in this work.

Compared with the growing information base on CH<sub>4</sub> emissions from oil and natural gas, the topic of well pad VOC and HAP emissions inspection and measurement is underdeveloped. Knowledge of CH<sub>4</sub> emissions has been driven by years of government and industry efforts (EPA, 2009, 2013b, 2010, 1993) and through a surge of recent research activity, in part enabled by the emergence of high-performance CH<sub>4</sub> measurement systems (Wang et al., 2008; Crosson, 2008; Pétron et al., 2012). Although CH<sub>4</sub> is ubiquitous in all phases of oil and natural gas production and distribution, product-related VOC and HAP emissions are confined primarily to upstream production activities and exhibit large basin-to-basin differences. These factors, combined with a lack of easily implemented field instruments to measure VOCs and HAPs, have made emissions data from well pads challenging to obtain. The intermittent nature of flash emissions, which occur when pressurized hydrocarbon liquids (oil or condensate) are transferred from a separator into a storage tank at atmospheric pressure, adds further complexity. Speciated emissions and control effectiveness are important emerging topics, especially in light of new regulations on condensate storage tank emissions designed to reduce ozone impacts (EPA, 2013a; CDPHE, 2008, 2014).

Development of cost-effective direct and remote measurement tools that can facilitate leak detection and repair, inform inventories, and support compliance activities is key to understanding well pad emissions. Manually executed well pad emission assessment techniques include optical gas imaging (OGI) devices that can efficiently detect the presence of hydrocarbon leaks (Carbon Limits, 2013; EPA, 2009), direct source measurements with high-volume samplers (HVSs), and bagging techniques to characterize and quantify component-level emissions (EPA, 2010). With supporting laboratory analysis, the latter can provide detailed speciated emission rate data but can be resource intensive and require special safety considerations. In the future, on-site (source) measurement approaches may be complemented with fence line sensor and remote mobile inspection techniques that provide higher levels of temporal and spatial coverage to help rapidly identify well pad malfunctions and gathering pipeline leaks (Brantley et al., 2014; Environmental Defense Fund [EDF], 2014; U.S. Department of Energy Advance Research Projects Agency-Energy [ARPA-E],

This paper compares VOC and HAP well-pad emission data from several studies that use different measurement approaches. New data from an EPA on-site study and a series of remote mobile surveys are compared with four previous onsite studies (Table 1). VOC and HAP well pad emissions are driven by hydrocarbon liquids (condensate or oil) production rates, basin profiles, and efficacy of pollution control strategies. Examples of well pad components used for pollution control are ECDs and vapor recovery units (VRUs).

The EPA study of well pad emissions in the Denver-Julesburg (DJ) Basin (Modrak et al., 2012) was similar in form to the City of Fort Worth Natural Gas Air Quality Study conducted by Eastern Research Group (ERG, 2011). Each study used OGI to locate emission points and HVSs to provide a rapidly executed measure of emissions. The studies differed in the canister analysis utilized and in the condensate production level and tank emission controls, with tank emissions from the ERG study ascribed primarily to produced water storage, emissions from which are not controlled but vented to the atmosphere. Only two of the sites in the ERG study utilized controls, whereas ECDs were present on all of the condensate tanks measured in the EPA on-site study.

Three other on-site studies conducted in Texas focused exclusively on well pad condensate tanks using a "seal and measure" approach where all potential emission points were routed through a single port monitored by a flow measurement device for extended time periods (Hendler et al., 2006; Gidney and Pena, 2009; ENVIRON, 2010). In these studies, the Gas Processors Association (GPA) method 2286-95 (GPA, 1999) was used to determine the composition of the vented gas. This somewhat invasive approach guarantees sampling of periodic flash emission events potentially missed by the short-duration, single-point HVS measurement. To further inform approach comparisons and source complexity, the on-site studies are compared with remote measurements of VOC and HAP well pad emissions acquired using a mobile inspection approach, EPA Other Test Method (OTM) 33A (EPA, 2014).

#### Methods

The EPA on-site study of 23 Weld County, Colorado, well pads in the DJ Basin was executed over a 1-week period in July 2011 by the same measurement team (Sage Environmental Consulting) using identical equipment and procedures similar to those detailed in the ERG study report (ERG, 2011; Modrak et al., 2012). Each pad in the EPA study contained on average 258 valves, 2583 connectors, three condensate tanks, a produced water tank, four thief hatches (one for each tank), five pressure relief devices, and three separators. All sites were fitted with one ECD as per current State of Colorado requirements. Four of the 23 sites were fitted with VRUs and one production pad contained a dehydration unit. Nineteen sites were fitted with single-stage separators, and four sites utilized two-stage separators and buffer tanks designed to reduce the pressure

Table 1. Comparison of field study attributes

Attribute	EPA On-site	EPA OTM 33A	ERG (2011)	Hendler (2006)	Gidney (2009)	ENVIRON (2010)
Yearof measurements 2011	; 2011	2010–2013	2010–2011	2006	2008	2010
Basins	Denver-Julesburg	Barnett, Denver-Julesburg, Pinedale	Barnett	Barnett, Western Gulf Anadarko, Barnett, Permian	Anadarko, Barnett, Permian	Barnett
Unique well pads (N)	23	Barnett: 26 Denver- Julesburg: 36 Pinedale: 61	380	Barnett: 10 Western Gulf: 9	Anadarko: 4 Barnett: 7 Permian: 8	က
A verage condensate 34.5 production (bbl/day)	34.5	Barnett: 0.15 Denver-Julesburg: 0.01 (6 pads with 6.7 Pinedale: 10.8 condensate production)	0.01 (6 pads with condensate production)	Barnett: 6.5 Western Gulf: 87.8	Anadarko: 72.8 Barnett: 22.3 Permian: 510.3	20.9
Controls at time of measurement	ECD, VRU condensate tanks	Denver-Julesburg: ECD, VRU Barnett: minimal Pinedale: partial	Minimal	None	None	None
Measurement approach	OGI, HVSwith GC- FID <sup>a</sup> canister analysis	OTM 33A for CH <sub>4</sub> with GC- FID <sup>a</sup> canister analysis	OGI, HVS with TO-15 canister analysis	Seal and measure with GPA method 2286-95 <sup>b</sup>	Seal and measure with GPA method 2286-95 <sup>b</sup>	Sea and measure with Sea and measure with GPA method GPA method GPA method 2286-95 <sup>b</sup> 2286-95 <sup>b</sup> 2286-95 <sup>b</sup>
Measurement focus Component (tank focus)		Integrated pad	Component (leak focus)	Condensate tank	Condensate tank	Condensate tank
Duration of measurement	minutes/point	20 min	minutes/point	24 hr	24 hr	24 hr

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Notes: ECD = enclosed combustor device, VRU = vapor recovery unit; OGI = optical gas imaging; HVS = high-volume sampler. \*Gas chromatography with flame ionization detection as described in EPA/600-R-36/ 1670 (EPA, 1998). \*Dess Processors Association method 2286-95 (GPA, 1999).

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of the liquid sent to the condensate tanks (to reduce flash emissions). Field conditions in the EPA study were sunny to partly cloudy, with temperatures ranging from 73.3 to 101.0 °F (average 87.8 °F). Following daily instrument quality assurance checks, site photos and details of the well pad equipment and layout were recorded, and an OGI emission inspection survey was conducted using a model GasFinderIR (FLIR, Inc., Billerica, MA), with emission points videodocumented. Based on the OGI survey, emission rate data were acquired using a HVS (Bacharach Hi Flow Sampler; Bacharach, Inc., New Kensington, PA) on all safely accessible emission points (Supplementary Material, Figure S1). For low emission rates where vapor concentrations were below the detection limit of the HVS, the concentration was determined with a Thermo Toxic Vapor Analyzer 1000B (Thermo Scientific, Franklin, MA).

From the largest emission point on each well pad, at least one sample was acquired at the exit of the HVS (N = 33 total) using a leak-free, subatmospheric 6-L stainless steel canister with a valve and passivated interior. The canister-derived concentration values were used with the measured HVS flow rates to calculate emission rates for individual and groups of compounds. Where canisters were not acquired, the default HVSderived emission rate was utilized. One major difference between the ERG (ERG, 2011) and EPA on-site studies is that the ERG study used EPA method TO-15 (EPA, 1999) for source canister VOC and HAP analysis and gas chromatography with a thermal conductivity detector for CH<sub>4</sub> analysis, whereas in the EPA on-site study the concentrations of total and speciated nonmethane volatile organic compounds were determined using gas chromatography with flame ionization detection (GC-FID) as described in EPA/600-R-98/161 (EPA. 1998) coupled with American Society for Testing and Materials (ASTM) 1946/D1945 (2010) analysis of CH<sub>4</sub>, ethane  $(C_2H_6)$ , and propane  $(C_3H_8)$ . EPA method TO-15 (EPA, 1999) is an ambient method, but was used by ERG for the source measurements in order to facilitate comparison with ambient measurements focusing on HAPs. The EPA on-site analysis set includes 57 compounds, 52 of which are VOCs, and has significantly more overlap with oil- and natural gas productrelated compounds, compared with the TO-15 method, which provides more coverage of general HAPs. Twenty-three VOCs are included in both the EPA on-site and ERG (ERG, 2011) analysis sets, but, notably, propane is omitted from the latter.

Off-site, or remote, measurements of CH<sub>4</sub> well pad emissions were collected using the EPA OTM 33A (EPA, 2014) mobile remote sensing approach during field campaigns in the Colorado DJ Basin, in July 2010 and 2011; Texas Barnett Shale, in September 2010 and 2011; and Wyoming Pinedale, which includes the Pinedale Anticline and Jonah fields, in June 2011, July 2012, and June 2013, and are detailed elsewhere (Brantley et al., 2014; EPA, 2014). For this approach, the sampling vehicle was positioned at a downwind observation location in the emission plume of the well pad using real-time CH<sub>4</sub> data from the concentration measurement instrument (CMI), either a G1301-fc cavity ring-down spectrometer (Picarro, Inc., Santa Clara, CA) or a GG-24-r off-axis integrated cavity output spectrometer (Los Gatos Research Inc.,

Mountain View, CA). During the CMI measurement, the engine was turned off and a 20-min observation was executed. When elevated CH $_4$  concentration levels were present, the operator triggered the acquisition of a nominal 30-sec duration evacuated canister sample, collocated with the CH $_4$  CMI inlet (Supplemental Material, Figure S2). The 1.4-L canisters were analyzed using the same method employed in the EPA on-site study (EPA, 1998; ASTM, 2010). The canisters provide snapshot measures of CH $_4$  and speciated VOC and HAP concentrations in the off-site plume representing distance-dispersed emissions from the well pad. The CH $_4$  concentrations were compared with the CMI measurements for quality assurance purposes.

To determine individual compound emission estimates, the OTM 33A (EPA, 2014) point-source Gaussian (PSG)  $CH_4$  emission assessment from the 20-min observation is used in conjunction with the canister data in a ratio-based approach (eq 1).

$$F_c \frac{1}{4} \frac{1}{6} C_c + F_o = C_o \frac{1}{4} M_c = M_o$$
 (1)

where  $F_c$  is the emission estimate of canister compound (g/sec);  $C_c$  is the measured concentration of canister compound (ppb);  $F_o$  is PSG the emission rate estimate for CH<sub>4</sub> (g/sec);  $C_o$  is CH<sub>4</sub> concentration in canister above background (ppb);  $M_c$  is the molecular weight of canister compound (g/mol); and  $M_o$  is the molecular weight of CH<sub>4</sub> (g/mol).

The acceptance criteria for the canister-based emission estimates include the criteria described for the CH $_4$  measurement (Brantley et al., 2014) with the additional criterion that canister-derived CH $_4$  concentrations exceed 100 ppb above the background value determined by the PSG calculation to ensure robust plume sampling. No background correction was applied to the nonmethane compounds, leading to a slight positive bias in results. As with the on-site measurements, the compound set for the OTM 33A VOC emission assessments includes all C3+ species present above detection limit in the canister analysis (EPA, 1998; ASTM, 2010). Propane concentrations determined using the ASTM method were utilized in the analysis because of the increased accuracy over the GC-FID method (EPA, 1998). The term VOC used herein does not include CH $_4$  or C $_2$ H $_6$  (ethane) species.

The HAPs quantified using GC-FID as described in EPA/600-R-98/161 (EPA, 1998) include benzene, toluene, ethylbenzene, m-xylene, o-xylene, and p-xylene (BTEX) as well as n-hexane and 2,2,4-trimethylpentane. Pring (2012) used the data collected by Hendler et al. (2006) to develop BTEX emission factors for condensate tanks in Texas. BTEX emissions measured in both the on-site and OTM 33A measurements were compared with the emissions measured by Hendler et al. (2006) and used by Pring (2012) as well as those measured by ERG for the City of Fort Worth (2011).

Study results were compared by summing individual emission point measurements from the on-site studies by pad to represent total emissions from the well pad and then using geometric means because both HAP and VOC emissions were log normally distributed. Henceforth, mean will refer to geometric mean unless otherwise specified. The mean and 95% confidence intervals (CIs) of the log-transformed data were

calculated using a nonparametric bootstrap (Wickham, 2009; Harrell and Dupont, 2007) and then transformed back into the original scale. The nonparametric bootstrap involved resampling with replacement 1000 times, the mean of each of the samples was taken and the 95% CIs were calculated from the resulting normally distributed means. The nonparametric bootstrap was chosen because it does not assume the underlying data comes from a normal distribution.

Information on condensate production was provided by the owners for 19 of the sites measured in the EPA on-site study. In addition, 14 of these sites had operator-provided high-pressure liquid sample analyses. For these sites, the E&P TANKS software version 2.0 (American Petroleum Institute, Washington, DC) was used to calculate the condensate tank potential to emit (PTE) under a variety of temperature and pressure conditions. The model inputs include the chemical composition of a liquid or gas sample, the American Petroleum Institute (API) gravity of the sales oil, ambient temperature and pressure, solar insolation, estimated annual production rate, and separator pressure and temperature. The model outputs include predicted uncontrolled emissions (PTE) of HAPs and of VOCs. Recent samples were collected at seven of the sites for extended natural gas liquid analysis, whereas analytical results from samples taken in 2009 or 2010 were available at the other seven sites. A range of ambient temperatures and pressures was used in the model representing the recorded ambient conditions when the emission measurements were made: 73.3 to 101 °F and 12.14 to 12.57 psia. The site operators provided separator pressures and temperatures, and condensate production rates.

#### Results and Discussion

#### Comparison of canister and HVS samples

In the EPA on-site study, a total of 106 emission points were observed with OGI and measured with the HVS and 33 evacuated canister samples were acquired and analyzed to establish the composition of the emitted vapor streams (Supplemental Material) and to compare with the HVS combustible concentration (% hydrocarbon [HC]) determination. In the DJ Basin, condensate tanks with six tons of emissions per year or greater are now required to be controlled to 95% either through flaring or vapor recovery pollution control practices (CDPHE, 2014).

Emissions in excess of this rate can be referred to as fugitives or leaks. Thief hatches were one of the most frequently observed leak locations on condensate tanks, indicating that the systems may not have been optimally controlled. As in most locations, emissions from produced water storage tanks were uncontrolled (vented) at the time of the study. The canister samples were divided into five categories based on the location of the emission (Table 2). Condensate tank working and breathing emissions were separated from flash emissions initially, but because the compositions were not substantially different, the categories were combined. The sampling protocol called for a canister sample to be acquired at the highest emission point on the pad, which was condensate tank-related in most cases (n = 27). The compositions of the condensate tank leaks were fairly consistent, with an arithmetic mean molecular weight of 41.9 g/mol (Table 2). The emissions with the largest fraction of carbon in the form of CH4 were collected from a dehydrator, whereas the emissions with the greatest fraction of carbon in the form of VOCs and HAPs were acquired from a produced water tank.

The HVS used in this study is designed for downstream natural gas leak measurements and has not been thoroughly evaluated for use in upstream well pad applications with mixed VOC and CH<sub>4</sub> emission streams. The HVS calculates emission rate by multiplying instrument flow rate by the sensor-determined combustible concentration (% HC, calibrated as CH<sub>4</sub>). The HVS determinations of % HC in the emissions were compared with the concentrations measured in the canister samples for the EPA on-site study. For emissions with ≤10% HC, the HVS and canister measurements were correlated with a slope of 1.1 and a coefficient of determination (R<sup>2</sup>) of 0.87 (Figure 1b). However, for canister samples with summed HC concentrations >10%, the HVS sensor underreported % HC (Figure 1a). In these cases, the HVS pellistor sensor or the control system is believed to have malfunctioned by failing to switch from catalytic oxidation (low range) to thermal conductivity mode (high range), causing significant underestimation of combustible concentration and therefore emission rate (Modrak et al., 2012). The results shown here differ slightly from those in Modrak et al. (2012) due to the correction of some data transcription errors. The changes did not affect the interpretation or implication of the results. This malfunction was detected only during large emissions from condensate tank thief hatches (VOC-rich stream) and may be partly due to an

Table 2. Arithmetic means, minimums, and maximums of molecular weight and percent of carbon in emissions in the form of CH<sub>4</sub>, VOCs, and HAPs from on-site canister samples by location

		% Carbon as CH <sub>4</sub>		% Carbon as VOC			% Carbon as HAP			Molecular Weight			
Location of emission	Ν	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max
Condensate tank	27	9.8	2.8	27.5	76.0	54.9	89.2	4.7	1.1	9.5	41.9	29.5	54.5
Dehydrator	1	64.4	64.4	64.4	15.8	15.8	15.8	0.3	0.3	0.3	19.7	19.7	19.7
Produced water tank	1	3.2	3.2	3.2	91.8	91.8	91.8	18.5	18.5	18.5	65.7	65.7	65.7
Separator/control valve	3	31.1	8.7	55.1	51.7	25.8	75.0	3.8	1.2	5.2	30.7	21.6	40.9
Well head	1	51.0	51.0	51.0	27.7	27.7	27.7	0.0	0.0	0.0	22.1	22.1	22.1

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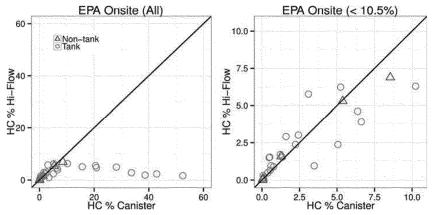


Figure 1. Comparison of HVS measurements and canister measurements. The solid black line represents y = x. Circles represent measurements of tank emissions, whereas triangles represent nontank emissions.

undetected range limitation of the instrument caused in part by limited airflow around the emission point (Supplemental Material, Figure S3). The four highest % HC measurements were acquired during condensate tank flashing, with the next four highest canister measurements exhibiting evidence of larger than typical breathing emissions (Supplemental Material). Further observations of this type of HVS malfunction resulting from the failure of the sensor to transition are described in Howard et al. (2015).

In the EPA on-site study at six of the sites, two canister samples of a condensate tank emission point were collected. At four of the sites, one sample represented a flashing emission whereas the other represented breathing emissions (Table 3). While being observed, the condensate tank measured at site E flashed 10 times within 20 min, indicating that although the measurements were not recorded as occurring during a flashing event, they likely represent more than breathing emissions. Flash emissions were always higher than breathing emissions, with VOC emissions increasing by 0.1–2 g/sec (Table 3). Because of the lack of reliability in the HVS % HC

measurements at elevated ranges, we were unable to obtain complete information on the duration of the flash emissions, although they were on the order of 30 sec to a couple minutes for the primary event. The temporal variability in emissions illustrates the need for cost-effective efficient measurement strategies for identifying significant leaks of an intermittent nature.

# Comparison of condensate canister measurements with modeled emissions

Condensate tank VOC and HAP emissions from the EPA on-site study were modeled using API E&P TANKS and compared with measurements (Figure 2). The modeled PTE values represent the combined flashing, working, and breathing emissions expressed as an average sustained emission rate in (g/sec). For each point, the error bars represent the maximum and minimum modeled values resulting from the range of ambient temperatures and pressures observed during the study with annual average insolation. The upper dashed line

Table 3. Repeat measurements of condensate tank emissions

Site	Condensate Production (bbl/day)	Flash Emission	HC % Canister	HC % HVS	Flow Rate (scfm)	VOC (g/sec)	CH <sub>4</sub> (g/sec)	HAP (g/sec)
V	18	No	1.22	1.71	5.4	0.02	0.01	<0.01
V	18	Yes	33.64	2.79	7.0	1.59	0.20	0.10
F	19	No	1.35	1.53	5.5	0.05	< 0.01	< 0.01
F	19	No	0.52	1.53	5.5	0.02	< 0.01	< 0.01
Q	27	No	2.24	2.38	5.4	0.09	<0.01	0.01
Q	27	Yes	5.06	2.38	5.4	0.20	0.01	0.01
U	27	No	20.51	5.5	6.8	0.66	0.15	0.01
U	27	Yes	38.64	1.88	7.0	1.50	0.23	0.02
Ε	29	No	28.15	4.94	4.8	0.83	0.10	0.05
Ε	29	No	20.87	4.71	4.7	0.55	0.08	0.03
Ρ	42	No	6.62	3.9	6.0	0.27	0.01	0.01
Р	42	Yes	52.44	1.67	6.0	2.32	0.09	0.07

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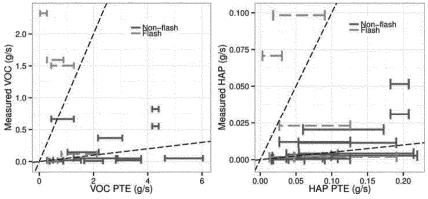


Figure 2. Comparison of VOC and HAP measurements with potential to emit values calculated using E&P TANKS version 2.0 (API Publication 4697) with a range of ambient temperatures (73.3–101 °F) and pressures (12.14–12.57 psia). Dashed lines represent y = x and y = 0.05x.

represents an ordinate-to-the-abscissa 1:1 value, whereas the lower dashed line is 5% of this slope, representing a 95% emission control value. As expected, two of the measurements made during flashing events were larger than the range of modeled VOC emissions. Flashing events are typically shortlived and cannot be extrapolated to yearly estimates without knowledge of their duration and frequency. Seven of the samples were completely below the 5% line for VOCs PTE and below the 5% line for the upper estimates of HAPs PTE, indicating that the sustained tank breathing emissions during near peak emissions conditions (daytime, summer) appear to be effectively controlled. Six of the measured emissions represent levels greater than 5% of the modeled potential to emit values for both VOCs and HAPs, but this does not take into account diurnal or seasonal effects which should reduce breathing emissions during colder times of the year. Two of these samples were taken at site E and may likely represent more than breathing emissions due to the high frequency of separator dumps at the time of measurement. Remote inspection techniques such as OTM 33A could be used to identify cases where emissions are not being effectively controlled.

#### Comparison of on-site and remote methods

To determine total well pad VOC and HAP emissions for the EPA on-site study, the HVS measurements without canister samples were assigned the arithmetic mean molecular weight (MW), percent VOC, and percent HAP concentrations by location category (Table 2). Measurements of documented flash emissions in the EPA on-site study were not included in the site totals, because the duration and frequency were unknown. All of the emissions measured with the HVS were then summed by site and compared with measurements from the EPA OTM 33A study as well as previously published studies. A total of 133 canister samples out of 201 collected remotely using OTM 33A met data quality criteria and were spatially matched with active well pads (Brantley et al., 2014).

The geometric means and corresponding 95% CIs of the onsite measurements of VOC emissions rates by Hendler et al. (2006), Gidney et al. (2009), and ENVIRON (2010) ranged from 0.32 (0.16, 0.62) g/sec to 2.94 (0.94, 9.85) g/sec (Figure 3). The lowest mean emission rate of these three studies that utilized GPA method 2286-95 (1999) was observed

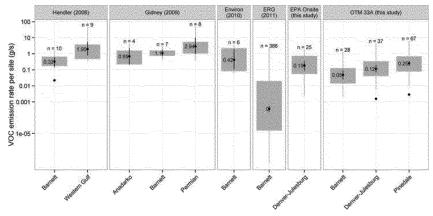


Figure 3. Comparison of VOC study results. Boxes represent the 1st and 3rd quartiles of the data, whereas whiskers extend to the largest measurement that is within 1.5 times the interquartile range. Geometric means are labeled and are shown in black along with 95% CIs and were calculated using a nonparametric bootstrap.

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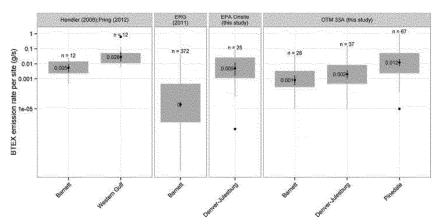


Figure 4. Comparison of HAPs study results. Boxes represent the 1st and 3rd quartiles of the data, whereas whiskers extend to the largest measurement that is within 1.5 times the interquartile range. Geometric means are labeled and are shown in black along with 95% CIs and were calculated using a nonparametric bootstrap.

by Hendler et al. (2006) at pads in the Barnett Shale, which also reported the lowest average condensate production rates for the set (6.5 bbl/day). The highest mean VOC emission rates were observed by Gidney et al. (2009) at sites in the Permian Basin with the largest average condensate production rates (510 bbl/day). However, mean VOC emissions measured by Gidney et al. (2009) in the Anadarko Basin, 0.69 (0.22, 3.11) g/sec, were lower than those in the Barnett, 1.10 (0.70, 1.75) g/ sec, despite the higher condensate production level, 72 and 22 bbl/day, respectively. This difference may be due to differences in condensate composition and engineering factors. The basinlevel VOC emission factors used in the 2011 EPA National Emissions Inventory (EPA, 2011) were 3.15, 7.07, 9.76, 11, 13.7, and 19.6 lbs VOC/bbl of condensate in the Anadarko, Permian, Fort Worth (Barnett), Western Gulf, DJ, and Pinedale basins, respectively. This general correlation of emissions with emission factor and production rate is to be expected, since the studies used the single-vent 24-hr measurement approach, where all flash and other emissions are represented.

In comparison, the ERG on-site study (2011) using instantaneous HVS measurement in the Eastern Barnett has the lowest mean well pad VOC emission rate by a large margin <0.01 (0.00, 0.00) g/sec (Figure 3). This result is in part due to extremely low condensate production at the sites measured, but also contributing to these low values is the choice of compounds (e.g., no propane) quantified in the canister sample analysis for VOC determination and short-term nature of the measurement. None of the ERG (2011) sites with VOC emissions greater than 0.1 g/sec measured with a canister sample reported condensate production, although production rates were unavailable for 3 of the 11 sites and all of the measurements were taken at either tank vents or thief hatches. The HVS measurements may also have missed flashing events on the pad because of the short-term nature of the measurements.

At 0.19 (0.09, 0.36) g VOC/sec mean, the EPA on-site study was significantly higher than the ERG results (2011) and significantly lower than the results of Hendler et al. (2006) in the Western Gulf, 1.95 (0.73, 5.23) g VOC/sec, and Gidney (2009)

in the Barnett Shale, 1.10 (0.70, 1.75) g VOC/sec, and Permian Basin, 2.94 (0.97, 10.38) g VOC/sec. Several competing factors complicate the comparison of VOC emissions measured in the EPA on-site study with the emissions measured in the other onsite studies, including differences in production levels, the presence of controls, basin emission factors, and measurement techniques. If the VOC emissions in the EPA on-site study were uncontrolled and routed through a single emission point, we would expect them to be higher than the emissions in the other basins due to the higher National Emissions Inventory (NEI) emission factor. However, because the EPA on-site measurements were component-level real-time measurements of controlled systems, we would expect them to be lower than the Hendler (2006), Gidney (2009), and Environ (2010) studies.

The OTM 33A method is most applicable as an inspection technique because of its higher leak detection threshold, and ability to detect  $\text{CH}_4$  plumes from off-site (Brantley et al., 2014; EPA, 2014). As a result, the emission rates measured by OTM 33A tend to represent the upper end of the emissions distribution. Furthermore, the OTM 33A measurements do not include background value corrections and thus may exhibit a slight positive bias.

The mean emission rate measured using OTM 33A in the DJ Basin, 0.12 (0.06, 0.20) g VOC/sec, was not significantly different from the EPA on-site mean, 0.19 (0.09, 0.36) g VOC/ sec, despite the lower average condensate production: 6.7 and 34.5 bbl/day, respectively. Calculating the potentially emitted VOCs using the NEI emission factor of 13.7 lbs VOC/bbl of condensate, pads that produced 34.5 and 6.7 bbl/day and consistently emitted 5% of their VOC PTE would result in constant emission rates of 0.12 and 0.02 g/sec, respectively. OTM 33A measurements in the DJ Basin generally focused on smaller pads, many of which had OGI-observed thief hatch seal leaks, and in some cases malfunctions (open thief hatches and failed pressure relief valves) so were nonoptimally controlled. The nominal 20min OTM 33A measurements may have also included flash emissions events. All measurements in the Barnett Shale both by ERG and using OTM 33A were acquired primarily on lower

condensate producing sites, with VOC emissions measured using OTM 33A found to be significantly higher, in part due to the differences in canister sample analysis methods between the studies. As was seen in the analysis of the CH<sub>4</sub> OTM 33A measurements (Brantley et al., 2014), emissions located and measured using OTM 33A are not readily explained by production.

Trends in HAP emissions (Figure 4) were similar to the VOC emission trends. In both the on-site and OTM 33A EPA studies, the measured HAP emissions were significantly greater than those reported by ERG (2011) but not significantly different from the uncontrolled emission measurements reported by Hendler (2006) and Pring (2012). HAP emissions measured using OTM 33A in Pinedale, 0.015 (0.007, 0.022) g BTEX/ sec, were significantly higher than those measured in the DJ Basin, 0.002 (0.001, 0.004) g BTEX/sec, and the Barnett, 0.001 (0.000, 0.002) g BTEX/sec. The differences in mean basin HAP emissions measured using OTM 33A are more pronounced than the differences in mean VOC emissions, which is in part due to a higher number of nondetects in the measurements from the DJ Basin and Barnett Shale. Other contributing factors may include differences in condensate composition, produced water production levels, and handling procedures in the different regions. Produced water ponds have been found to be significant sources of HAPs (Thoma, 2009), and the canister sample with the highest percentage of carbon in the form of HAPs in the EPA on-site study was collected at a produced water tank (Table 2).

## Summary

Responsible oil and natural gas development requires an improved understanding of air emissions from production operations. Although a significant amount of research has recently been conducted to investigate CH<sub>4</sub> emissions (Allen et al., 2013; Brantley et al., 2014; Brandt et al., 2014), VOC and HAP emissions from upstream production operations are also important due to their potential impact on regional ozone levels and proximate populations. This study provides important information on the sources and variability of VOC and HAP emissions from production pads as well as a comparison between different measurement techniques and laboratory analysis protocols. Our finding that the HVS can malfunction and underestimate emissions suggests that the instrument may not be suitable for general use in upstream applications, measuring tank emissions in particular, without canister measurement normalization. The similarity between the concentrations measured on-site and those measured remotely suggests that OTM 33A can be used effectively as an inspection technique for identifying oil and gas well pads with large fugitive emissions. The EPA on-site and OTM 33A studies in the DJ Basin conducted under peak summertime conditions, in the 2010-2011 time frame, indicate that significant VOC emissions from controlled systems can occur and are often a result of thief hatch leaks. Due to recent changes in state regulations, the current field conditions may differ from those presented here.

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#### Disclaimer

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### Supplemental Material

Supplemental data for this paper can be accessed on the publisher's website.

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#### About the Authors

Halley Brantley is an Oak Ridge Institute of Science and Education (ORISE) fellow at the U.S. Environmental Protection Agency and a doctoral student in Statistics at North Carolina State University.

Eben D. Thoma and Adam P. Eisele are scientists at the U.S. Environmental Protection Agency.

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# Sensor transition failure in the high flow sampler: Implications for methane emission inventories of natural gas infrastructure

Touché Howard<sup>a</sup>, Thomas W. Ferrara<sup>b</sup> & Amy Townsend-Small<sup>c</sup>

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<sup>&</sup>lt;sup>a</sup> Indaco Air Quality Services, Inc., Durham, NC 27713 USA

<sup>&</sup>lt;sup>b</sup> Conestoga-Rovers & Associates, Niagara Falls, NY 14304 USA

<sup>&</sup>lt;sup>c</sup> Department of Geology, University of Cincinnati, Cincinnati, OH 45221 USA Accepted author version posted online: 24 Mar 2015.

# Sensor transition failure in the high flow sampler:

# Implications for methane emission inventories of

# natural gas infrastructure

Touché Howard<sup>1</sup>, Thomas W. Ferrara<sup>2\*</sup>, and Amy Townsend-Small<sup>3</sup>

<sup>1</sup>Indaco Air Quality Services, Inc.

Durham, NC 27713 USA

<sup>2</sup>Conestoga-Rovers & Associates

Niagara Falls, NY 14304 USA

<sup>3</sup>Department of Geology

University of Cincinnati

Cincinnati, OH 45221 USA

About the Authors

**Touché Howard** is a chemical engineer in Durham, North Carolina and the developer of the high volume sampler.

**Thomas Ferrara** is the manager of the Conestoga Rovers & Associates, Inc. source measurement group in Niagara Falls, New York.

**Dr. Amy Townsend -Small** is an assistant professor of geology at the University of Cincinnati in Cincinnati, Ohio.

\*Corresponding author: tferrara@craworld.com; (716) 297-6150

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Abstract: Quantification of leaks from natural gas (NG) infrastructure is a key step in reducing emissions of the greenhouse gas methane (CH 4), particularly as NG becomes a larger component of domestic energy supply. The United States Environmental Protection Agency (USEPA) requires measurement and reporting of emissions of CH 4 from NG transmission, storage, and processing facilities, and the high flow sampler (or high volume sampler) is one of the tools approved for this by the USEPA. The Bacharach Hi -Flow® Sampler (BHFS) is the only commercially available high flow instrument, and it is also used throughout the NG supply chain for directed inspection and maintenance, emission factor development, and greenhouse gas reduction programs. Here we document failure of the BHFS to transition from a catalytic oxidation sensor used to measure low NG (~5% or less) concentrations to a thermal conductivity sensor for higher concentrations (from ~5% to 100%), resulting in underestimation of NG emission rates. Our analysis includes both our own field testing as well as analysis of data from two other studies (Modrak et al., 2012; City of Ft Worth, 2011). Although this

failure is not completely understood, and although we do not know if all BHFS models are similarly affected, sensor transition failure has been observed under one or more of these conditions: 1), calibration is more than ~2 weeks old; 2), firmware is out of date; or 3), the composition of the NG source is less than ~91% CH<sub>4</sub>. The extent to which this issue has affected recent emission studies is uncertain, but the analysis presented here suggests that the problem could be widespread. Furthermore, it is critical that this problem be resolved before the onset of regulations on CH 4 emissions from the oil and gas industry, as the BHFS is a popular instrument for these measurements.

**Implications**. An instrument commonly used to measure leaks in natural gas infrastructure has a critical sensor transition failure issue that results in underestimation of leaks, with implications for greenhouse gas emissions estimates as well as safety.

## Introduction

Fugitive emissions of methane (CH<sub>4</sub>) from natural gas (NG) extraction, processing, transmission, and distribution are among the largest anthropogenic sources of CH<sub>4</sub> globally (Kirschke et al., 2013) and in the United States (USEPA, 2014). Emissions of CH<sub>4</sub> may increase as the United States and other nations exploit NG from shale (via hydraulic fracturing or "fracking") to replace coal and oil. Because CH<sub>4</sub> is a greenhouse gas 28 to 34 times more powerful than carbon dioxide (CO<sub>2</sub>) on a 100-year time scale (Myhre et al., 2013), increases in NG infrastructure due to this transition may increase regional or global greenhouse gas emissions, despite the fact that burning NG emits less CO<sub>2</sub> per unit of energy returned than coal or oil (Howarth et al., 2011; Wigley, 2011).

The Bacharach Hi -Flow® Sampler (BHFS; Bacharach, Inc., New Kensington, PA), the only commercially available version of the high flow sampler (sometimes also referred to as the "high volume sampler"), was brought to market in 2001. Since then, the instrument's use has broadened from the transmission, storage, and distribution segments to include increased use in production, and it has been used to measure NG emission rates from sources throughout the NG supply chain (Allen et al., 2013; 2014; ACR, 2010; City of Fort Worth, 2011; GTI, 2013; Modrak et al., 2012 ; USEPA 2006; USBLM, 2011). The high flow sampler is also one of the methods approved by the United States Environmental Protection Agency (USEPA) for mandated measurement s of NG leaks from transmission, storage and processing facilities (CFR, 2010). However, at least one previous study has found that this sampler may underreport emission rates by as much as NG streams with <95 % CH<sub>4</sub> such as two orders of magnitude when used to measure commonly found at production sites (Modrak et al., 2012). Additionally, there is increasing evidence that ground -based (or "bottom-up") estimates of CH<sub>4</sub> emissions underreport emissions when compared to "top-down" estimates, thought to be due to erroneously low emissions factors reported for NG systems, resulting in low "bottom-up" estimates (Miller et al., 2013; Brandt et al., 2014).

The high flow rate sampling technique uses a high flow rate of air and a loose enclosure to completely capture the NG emitting from a source (Indaco, 1995; Howard, 2001). The emission rate is calculated as follows:

$$Q_{NG} = F_{sampler} \times (C_{sample} - C_{background}) / R$$
 (1)

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where:

 $Q_{NG}$  = the emission rate of NG from the source (scfm),

 $F_{\text{sampler}}$  = the sample flow rate of the sampler (scfm),

C<sub>sample</sub> = the concentration of NG in the sample flow (%NG)

indicated by the BHFS,

 $C_{background}$  = the concentration of NG in the background near the component ( % NG) indicated by the BHFS, and

R = the response factor of the instrument (see below for an explanation of response factor).

The BHFS uses a catalytic oxidation sensor to measure concentrations from 0% to approximately 5% NG, and a thermal conductivity sensor for concentrations from approximately 5% to 100% NG. The catalytic oxidation sensor is typically calibrated with 2.5% CH<sub>4</sub> in air and the thermal conductivity sensor is calibrated with 100 % CH<sub>4</sub> (Bacharach, 2010) Both sensors primarily respond to CH 4, and, to a lesser extent, ethane (C<sub>2</sub>H<sub>6</sub>), but have a lower response to heavier hydrocarbons and non-hydrocarbons. A response factor correction is necessary to account for differences between the calibration gas, which consists of only CH 4, and the NG being sampled, which can have other hydrocarbons in addition to CH 4. For example, if the instrument indicates a concentration of 80 % NG in the presence of 100 % NG, then the response factor is 0.8. Actual concentration is calculated by dividing the indicated concentration

by the response factor. The response factors for the catalytic oxidation sensor and the thermal conductivity sensor might differ from each other for the same composition of NG depending on which components of NG other than CH<sub>4</sub> are present.

The manufacturer recommends sensor calibration every 30 days, either by shipping the instrument to a service center or by the user (Bacharach, 2010). The calibration may also be checked ("bump-tested") periodically by the user. Both procedures involve introducing the calibration standards to the instrument, but an actual calibration adjusts the gain of the calibration amplifier as needed, while the bump test only indicates the response of the sensor compared to the known concentration of the calibration gas (Bacharach, 2010).

Here we detail the results of a testing program conducted to understand the effects of NG composition, calibration status, and firmware status on the BHFS. We also present a reanalysis of recently published data on CH 4 emissions from NG production sites, and demonstrate the instrument likely failed at some of those testing sites (Modrak et al., 2012; City of Fort Worth, 2011).

# Methods

In order to investigate the performance of the BHFS, field testing was conducted at five different NG production sites with wellhead gas CH<sub>4</sub> concentrations ranging from 66% to 90.8%. A summary of the field tests is shown in Table 1; the compositions of the NG streams at the production sites are shown in Table 2. NG sampling and composition

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analysis (via gas chromatograph-flame ionization detector (GC-FID)) were conducted by the host company just prior to the sampler testing. We also conducted a laboratory test using commercial grade CH<sub>4</sub> (> 99.9%).

The tests were conducted by metering known fl ow rates of NG into the sampler inlets through a rotameter (King Instrument Company, Garden Grove, CA; 0 to 10 scfm air scale). The sample concentration indicated by the internal BHFS sensor was recorded and compared to an external gas concentration monitor used to measure the actual NG concentration at the sampler exhaust (Bascom -Turner Gas Sentry CGA 201, Norwood, MA). The Gas Sentry unit was calibrated with 2.5 % and 100% CH<sub>4</sub> prior to each field day; exhaust concentrations measured using this unit differed from calculated concentrations (calculated using the sampler flow rate and amount of NG metered into the inlet) by an average of ± 6%.

Five samplers were tested during this program at 5 sites with varying NG composition s (Tables 1 and 2). Samplers 1 and 2 were tested in the first quarter of 2013, the first at Site A and the second at Site B (Table 1). The firmware version on these samplers was not recorded, but was prior to version 3.03 (released in April, 2012). These samplers were fully calibrated within 3 days of the testing conducted at the field sites and were not used for any other measurements before these tests were conducted. Each BHFS unit was bump tested at each field site prior to and after the field -testing using 2.5 % CH<sub>4</sub> in air and 100% CH<sub>4</sub>.

Follow-up testing was then conducted in March of 2014. During this program, samplers 3, 4, and 5 were each tested under a variety of different conditions (Table 1) at Sites C, D, and E with different NG compositions (Table 2). Sampler 3 had firmware version 3.04 (September, 2013); this sampler was calibrated two weeks prior to the field test and had been used for emission measurements at production sites since that time. Samplers 4 and 5 had firmware version 3.03 (April of 2012); these two samplers were calibrated each day before beginning field tests. Bump testing was also conducted on all of these instruments prior to the start of these follow-up tests.

The sample flow rate measurement (which in the BHFS is calculated from the pressure drop across an orifice plate) might be affected by as much as 20 % by variations in NG densities at our test sites compared to CH 4. We have eliminated this variability in our analysis by directly comparing the NG sample concentration indicated by the BHFS sensor to the external measurement by the Gas Sentry as opposed to comparing emission rates reported by the BHFS to the emission rates metered into the sampler.

# **Results and Discussion**

## Evidence for sensor transition failure

Our initial tests with sampler 1 at site A and sampler 2 at site B showed that the internal sample stream sensor could not accurately measure concentrations that exceeded 6 % NG in air with wellhead gas compositions of 66.3 % and 77.8% CH<sub>4</sub> (Fig. 1, Table 1). Above 6% NG, both samplers 1 and 2 indicated NG concentrations that rose and fell

continuously between 1.1 % and 5.9 %, even though the actual sample concentrations ranged from 7% to 73% NG in air (Fig. 1). Since the instrument is expected to transition from the catalytic oxidation sensor to the thermal conductivity sensor above approximately 5% NG, we concluded that the instruments were not properly transitioning between sensors. After this behavior was observed, the samplers were restarted, but the problem persisted. However, sampler 1 performed normally with commercial purity (>99.9%) CH<sub>4</sub> (Fig. 1).

Further testing showed that the sensor transition failure problem also occurred in sampler 3, which had firmware version 3.04 (Fig. 2). As seen in Figure 2, sensor transition failure for this sampler occurred in two test runs at Site C (90.8 % CH<sub>4</sub>). In this case, after sensor transition failure occurred, this sampler was calibrated (not simply bump tested) and this eliminated any further sensor transition failures that day. This sampler was calibrated prior to use the following day and performed correctly at Sites D and E (data not shown), with high concentrations of heavier hydrocarbons (Table 2).

Samplers 4 and 5 which had firmware version 3.03 and were calibrated (again, not simply bump tested) each day before the testing was conducted, did not show any evidence of sensor transition failure during testing at Sites C, D, and E (data not shown).

We have shown that NG concentrations reported by the BHFS can be more than an order of magnitude too low, likely because the sampler does not properly transition between sensors, even at sites with CH 4 concentrations as high as 90.8 %. Since the sample concentration is used to calculate emission rates, these errors would directly translate into

reporting of erroneously low emission rates. This problem may be prevented with installation of the proper firmware, as sensor transition failure was not observed with firmware version 3.03, but it was observed with earlier versions and 3.04 , and/or with more frequent calibration, as mid-day calibration of sampler 3 appeared to prevent further incidents of sensor transition failure during that sampling day (Figs. 1 and 2). We have also shown that sensor transition failure can occur even with updated firmware if the calibration is as much as two weeks old (even though that is within the manufacturer 's guidelines), again at sites with CH 4 concentrations as high as 91 % (Fig. 2). Further testing is needed on these instruments to determine the exact cause of these anomalously low measurements, and future work would benefit from more systematic testing of the impact of time since calibration, firmware version, and NG composition on performance of the BHFS sensors. Acknowledging this uncertainty, however, it is clear that this problem may lead to reporting of erroneously low CH4 leak rates.

## Response factor versus sensor transition failure

We also performed tests of the response factor of the thermal conductivity sensor, or the indicated response of the instrument compared to the actual concentration of NG. The response factor of the Bacharach sensor to NG was recorded at Sites A and C. At Site A, the sensor indicated a NG concentration of 74 % for 100% gas (with CH 4 and C 2H6 concentrations of 66.3 % and 13.7 %, respectively) and at Site C, the sensor indicated 87.5% for 100% gas (with CH4 and C2H6 concentrations of 90.8% and 0.25%, respectively) (Table 1). For tests during which the BHFS transitioned to the thermal

conductivity scale, the ratio of the BHFS sample c oncentrations to the exhaust sample concentrations measured by the external Bascom Turner Gas Sentry unit was  $1.014 \pm$ 0.035 (using a 95 % confidence limit). The response of the thermal conductivity sensor for both the BHFS and the Gas Sentry is similar and decreases with increasing heavier hydrocarbon concentrations. This is expected since the thermal conductivit ies of the heavier hydrocarbons are less than that of CH  $_4$  (ranging from 61% for  $C_2H_6$  and 48% for butane compared to CH<sub>4</sub> (NIST, 2011). It is interesting to note that correcting the sensor response based only on thermal conductivity and gas composition would still result in readings that would be 5 % to 15% too low depending on gas composition, so empirical response factors based on actu al instrument response appear to be the most accurate method to correct for response factor. However, our tests show that the issues described in Figures 1 and 2 are distinct from a response factor issue, as the errors in these tests magnitude than could be explained by response factor alone. were of a much larger Decreases in response due to gas composition were small compared to the magnitude of the sensor transition failure and this factor was eliminated in our field tests (Figures 1 and 2) by comparing the BHFS results to that of the Gas Sentry, which has a very similar response factor

At least one previous study has observed erroneously low emission rates using the BHFS and attributed these errors to response factor issues, noting that the BHFS does not provide accurate results when surveying NMHC -rich gas streams (< 95 % CH<sub>4</sub>) (Modrak et al., 2012). These measurements were made at 23 production sites, including condensate tanks, pressure relief devices, produced water tanks, pneumatic devices, and

connectors. Additionally, Modrak et al. (2012) collected canister samples from the sampler exhaust and found that the sample concentrations measured by the BHFS could be significantly lower than the actual concentrations (measured by GC-FID) when heavier hy drocarbons were present. Modrak et al. (2012) used the canister results to recalculate emission rates from the BHFS and found that the BHFS could underreport the actual emission rate by as much as two orders of magnitude for sources such as condensate tanks, and that errors increased with increasing heavier hydrocarbon concentrations, attributed to response factor issues.

Our re-analysis of the data presented in Modrak et al. (2012) indicates this issue may have been caused by sensor transition failure, an duot response factor (Fig. 3). For the seven cases where that study provided both the BHFS emission rate and the net difference between that emission rate and the one they calculated using canister data, we have calculated the BHFS sample concentration by assuming a sample flow rate of 8 scfm, which is the average flow rate used by the instrument (Bacharach, 2010). As shown in Figure 3, this calculation indicates that the BHFS underestimated the actual NG concentration as measured by canister sample between 5 and 320 times, respectively (Fig. 3). All of the BHFS concentration measurements fall in the catalytic oxidation sensor range, even though the canister measurements indicated that there were numerous sample concentrations between 5 % and 50 %, which should have initiated a transition to the thermal conductivity sensor (Fig. 3). This would explain why the errors they observed were orders of magnitude too low as opposed to response factor changes that might cause underreporting by up to a factor of two. We note that since the work conducted by

Modrak et al. (2012) was done in July 2011, the sampler used in that program would have had a firmware version earlier than 3.03.

Implications: Fort Worth Air Quality Study

The City of F ort Worth Natural Gas Air Quality Study also collected canister samples from the exhaust of the BHFS during measurements at NG production sites made in 2010 and 2011 (City of Fort Worth, 2011). During this work, over 2100 measurements were made using the BHFS at 388 sites; canister—samples were collected from the sampler exhaust for 164 of those measurements. Figure 4 presents the sample concentration indicated by the BHFS as a function of CH<sub>4</sub> concentration measured by canister sampling of the exhaust and subsequent analysis by gas—chromatography—thermal conductivity detector (GC-TCD).

Figure 4 here

As discussed previously, the BHFS sensors respond to other compounds in NG besides  $CH_4$ , so it is expected that the indicated sample concentration would exceed the  $CH_4$  concentration measured in the canister, and that is the case for most of the comparisons in Figure 4. However, there were at least seven instances for which the sample concentration indicated by the BHFS was at or below 5% where the canister  $CH_4$  concentration ranged from 6.1 % to 90.4% (Fig. 4). These occurrences are most likely due to sensor transition failure. Additionally, the calibration protocol for this study was to calibrate the sampler sensors at the start of the field campaign, and then bump test the sensors to check that the sensor response was within  $\pm 10\%$  of the calibration gas value

(City of Fort Worth, 2011), while our work has shown that more frequent recalibration may minimize the occurrence of sensor transition failure. As with Modrak et al., since this work was done in 2010 and 2011, the sampler used would not have had the update to firmware version 3.03.

The third factor which appears to affect sensor transition failure, the concentration of CH<sub>4</sub> in the wellhead gas, was not known for eac h measurement in the F ort Worth data set. However, previous work has shown that NG wells in Tarrant County, Texas (Fort Worth's county) have an average CH<sub>4</sub> content of 94.2% and a median content of 96.0% (Zumberge et al., 2012). The generally dry gas in this area may be a factor in the relatively low occurrence of sensor transition failure in this data set.

## **Conclusions**

We have shown that the BHFS instrument can make erroneously low estimates of NG emissions that may affect measurements made through out the NG supply chain. We do not know exactly what conditions (firmware version, calibration interval, or concentration of CH<sub>4</sub> in the NG) may lead to sensor transition failure in the BHFS instrument, and there may be other variables that affect the inst rument's performance, such as sensor age. Future work would benefit from systematic analysis of these factors to determine the best operating conditions for the BHFS. However, our preliminary work indicates that daily calibration and/or use of firmware version 3.03 may minimize the occurrence of sensor transition failure in the BHFS.

Sensor transition failure was observed in measurements at sites with CH 4 concentrations in the wellhead gas ranging from 66.3% to 90.8%. Consequently, this phenomenon may occur throughout the NG industry, not just at production and processing sites with higher concentrations of > C<sub>2</sub> hydrocarbons, but also at transmission and distribution sites, even though CH<sub>4</sub> concentrations at those sites typically exceed 90 %. One example would be measurements made under EPA Subpart W at transmission sites, where use of the flow sampler (of which the BHFS is the only commercially available model) is approved for reporting purposes (40 CFR 98.233). Occurrence of sensor transsition failure would result in emission inventories being reported to that program as erroneously low. This phenomenon may also play a role in the discrepancy between top down and bottom up inventories, since it could result in low emissions factors used to scale CH 4 emissions from the ground level (Miller et al., 2013; Brandt et al., 2014). Because regulation CH<sub>4</sub> leaks from NG production and distribution systems is imminent, and because these leaks may create hazardous conditions along the NG supply c hain, it is essential that proper methodology is employed for leak rate measurements.

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Table 1. Summary of sampler testing

Sampler ID	Site	Firmware	Calibration Status	Number of Tests	Sensor Transition Failure Rate	Comments
BHFS 1	A	Prior to V. 3.03	Within 3 days of testing	27	25 (92.6%)	Lab testing with 99.9% CH <sub>4</sub> showed no sensor transition failures.
BHFS 2	В	Prior to V. 3.03	Within 3 days of testing	6	4 (66.6%)	One test showed BHFS sensor response 5 times too low compared to the external sensor. This was not counted as failure since the BHFS apparently transitioned into the thermal conductivity range.
BHFS 3	C, D, E	V. 3.04	Two weeks prior to testing, then after failure occurred	8 prior to calibration 5 after calibration	2 (25%) prior to calibration; 0 after calibration	Sensor transition failure occurred after six tests in 20 minutes. Only two tests were conducted before the instrument was recalibrated after the failure appeared, both of which showed failure
BHFS 4	C, D, E	V.3.03	Immediately prior to testing	10	0	
BHFS 5	C, D, E	V.3.03	Immediately prior to testing	15	0	
	<u></u>	28				

**Table 2.** Well head gas composition at test sites (volume %)

Gas Component	Site A Permian Basin	Site B Barnett Shale	Site C Eagle Ford	Site D Eagle Ford	Site E Eagle Ford
Methane	66,26	77.81	90.81	80.81	76.98
Ethane	13.66	10.82	0.25	11.94	13.10
Propane	10.29	5.02	0.03	3.23	4.95
Carbon Dioxide	0.34	2.26	8.76	2.02	2.37
n-Butane	3.76	1.40	0.00	0.56	0.30
Nitrogen	2.23	1.20	0.11	0.19	0.53
i-Butane	0.98	0.44	0.00	0.56	0.15
n-Pentane	0.87	0.38	0.00	0.14	0.07
Hexane	0.75	0.38	0.05	0.19	0.10
i-Pentane	0.83	0.30	0.00	0.17	0.19
Hydrogen Sulfide	0.00	0.00	0.00	0.004	0.03

Figure 1. NG concentrations measured by BHFS (samplers 1 and 2) versus concentrations via the external Gas Sentry for natural gas with varying content of CH 4. The dashed line indicates 5% sample concentration threshold, or the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity.

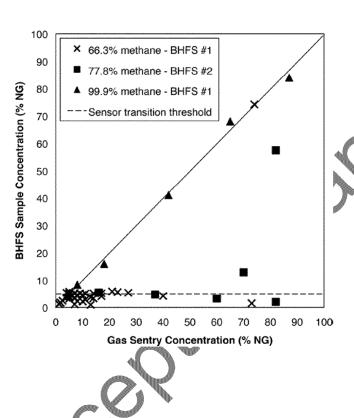


Figure 2. NG concentrations measured by BHFS (sampler 3) versus concentrations via the external Gas Sentry for natural gas at site C, 90.8 % CH<sub>4</sub>. The dashed line indicates 5% sample concentration threshold, or the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity.

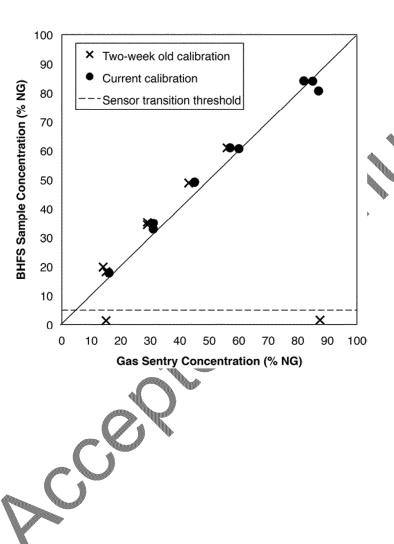


Figure 3. NG concentrations measured by the BHFS (calculated using an assumed BHFS flow rate of 8 scfm) versus concentrations via GC-FID ("actual sample concentration"). The dashed line indicates 5% sample concentration threshold, or the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity. Data are from Modrak et al. (2012).

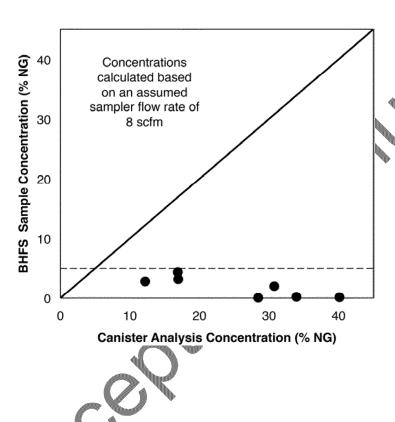
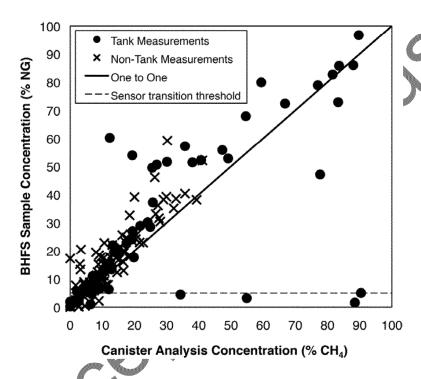


Figure 4. NG concentrations measured by the BHFS versus sample CH 4 concentrations via canister sampling with subsequent GC-TCD. The black line indicates where concentrations from both methods coincide. The dashed line indicates 5% sample concentration threshold, or the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity. Data are from City of Fort Worth Natural Gas Air Quality Study (2011).



To: allen@che.utexas.edu[allen@che.utexas.edu]; matt.harrison@urs.com[matt.harrison@urs.com]; Herndon@aerodyne.com[Herndon@aerodyne.com]; colm.sweeney@noaa.gov[colm.sweeney@noaa.gov]; gabrielle.petron@noaa.gov[gabrielle.petron@noaa.gov]; anna.karion@noaa.gov[anna.karion@noaa.gov]; bguven@harc.edu[bguven@harc.edu]; Thoma, Eben[Thoma.Eben@epa.gov]; blamb@wsu.edu[blamb@wsu.edu]; tferrara@craworld.com[tferrara@craworld.com]; sedburg@wsu.edu[sedburg@wsu.edu]; toward@craworld.com[toward@craworld.com]; james.whetstone@nist.gov[james.whetstone@nist.gov]; pshepson@purdue.edu[pshepson@purdue.edu]; nathan@bu.edu[nathan@bu.edu]; jackson@duke.edu[jackson@duke.edu]; swofsy@seas.harvard.edu[swofsy@seas.harvard.edu]; kmckain@seas.harvard.edu[kmckain@seas.harvard.edu]; Joe.von\_Fischer@colostate.edu[Joe.von\_Fischer@colostate.edu]; Nigel.Clark@mail.wvu.edu[Nigel.Clark@mail.wvu.edu]; Bryan.Willson@ColoState.EDU[Bryan.Willson@ColoState.EDU]; Dan.Zimmerle@ColoState.EDU[Dan.Zimmerle@ColoState.EDU]; alr@andrew.cmu.edu[alr@andrew.cmu.edu]; subu@cmu.edu[subu@cmu.edu]; Anthony.Marchese@ColoState.EDU[Anthony.Marchese@ColoState.EDU]; amy.townsendsmall@uc.edu[amy.townsend-small@uc.edu]; rella@picarro.com[rella@picarro.com]; david.lary@utdallas.edu[david.lary@utdallas.edu] Noelle Gaughen[ngaughen@edf.org]; Lauren Whittenberg[lwhittenberg@edf.org]; Drew Cc:

Nelson[dnelson@edf.org]; Ramon Alvarez[RAlvarez@edf.org]; Robert Harriss[rharriss@edf.org]

From: Steven Hamburg

Sent: Sun 9/29/2013 6:01:15 PM

Subject: Verifying affiliations of EDF's research parnters

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# Dear Scientific Collaborators:

Thank you for your responses to my earlier e-mail. As noted previously, in an effort to be fully transparent regarding the methane research projects EDF is helping to facilitate, EDF will be listing all scientists involved in theses project on our website.

You all saw an earlier version of the list of collaborators, but we have since realized that to execute effectively against our aim of full transparency we needed to augment that earlier list by including degrees, affiliations, and titles for those individuals listed. That revised list is attached for your review, sorry for asking one more favor, but we want to make sure that we get all of the details correct. Please verify that your name, title, and degree are correct. Please note that not all of the scientists listed in the attachment are on this email; PI's, please work with those involved in your projects to ensure that the list accurately reflects their information too. Please send any changes to ngaughen@edf.org by COB Friday, October 4th. If we do not hear from you, we'll assume your information is correct and post as is. We'll pass along the link to the final web page once it's up.

Thanks for all of your efforts to help clarify the natural gas related aspects of the methane budget of the US.
Cheers,
Steve
Steven Hamburg, PhD
Chief Scientist
Environmental Defense Fund

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University of Texas at Austin Melvin H. Gertz Regents Chair in Chemical Engineering Chair of the US Environmental Protection Agency's Science Advisory Board

# Brent Bailey, M.S.

Coordinating Research Council, Inc. Executive Director

# Donald R. Blake, Ph.D.

University of California, Irvine Professor, Chemistry and Earth System Science

# George Burba, Ph.D.

LI-COR Biosciences

Principal Scientist & Technical Group Leader

# **Daniel Carder**

West Virginia University
Director, Center for Alternative Fuels Engines and Emissions

# Nigel Clark, Ph.D.

West Virginia University
Professor, Mechanical and Aerospace Engineering
George B. Berry Chair of Engineering
Professor, Benjamin M. Statler College of Engineering and Mineral Resources

# Eric Crosson, Ph.D.

Picarro

Chief Technology Officer

# Kenneth J. Davis, Ph.D.

Pennsylvania State University
Professor, Meteorology
Co-Chair, North American Carbon Program Science Steering Group
Chief Science Officer, CarbonNowCast

# **Adrian Down**

Duke University Doctoral Student

# Steven Edburg, Ph.D.

Washington State University
Assistant Research Professor, Department of Civil & Environmental Engineering

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#### Thomas Ferrara, M.S.

Conestoga-Rovers & Associates

Project Manager

# Matthew Fraser, Ph.D.

Arizona State University

Senior Sustainability Scientist, Global Institute of Sustainability Associate Professor, School of Sustainable Engineering and the Built Environment Executive Director, Quantum Energy and Sustainable Solar Technology Center

# Birnur Guven, Ph.D.

Houston Advanced Research Center Research Scientist, Environmental Modeling

# Mike Hannigan, Ph.D.

University of Colorado Assistant Professor, Mechanical Engineering

# Matthew Harrison, P.E.

URS Corporation

Senior Greenhouse Gas Project Manager

# Al Hendler, M.S.

**URS** Corporation

Project Manager

# Scott Herndon, Ph.D.

Aerodyne Research, Inc.

Physical Chemist and Principal Scientist, Center for Atmospheric and Environmental Chemistry

# Daniel Hill, P.E.

Texas A&M University

Department Head, Professor and holder of the Noble Chair

# Touche Howard, M.S.

Conestoga-Rovers & Associates Research Engineer

# Lucy Hutyra, Ph.D.

**Boston University** 

Assistant Professor, Earth & Environment

# Robert Jackson, Ph.D.

**Duke University** 

Nicholas Professor of Global Environmental Change Associate Dean for Research and Professor of Biology

# Derek Johnson, Ph.D.

West Virginia University

Research Assistant Professor, Mechanical and Aerospace Engineering

# Anna Karion, Ph.D.

National Oceanic and Atmospheric Administration (NOAA) University of Colorado at Boulder Research Scientist

# David Kittelson, Ph.D.

University of Minnesota

Frank Rowley Professor, Mechanical Engineering

# Charles Kolb, Ph.D.

Aerodyne Research, Inc.

President & CEO

# Jeff Kuo, Ph.D., P.E.

California State University, Fullerton

Professor & Program Coordinator, Environmental Engineering

# Patrick Laine, Ph.D.

University of Houston

Post-Doctoral Fellow 2, Atmospheric Chemistry

# Brian Lamb, Ph.D.

Washington State University

Professor, Department of Civil & Environmental Engineering

# David Lary, Ph.D.

University of Texas at Dallas

Research Scientist, Environmental Modeling

# Michael Levi, Ph.D.

Council on Foreign Relations

David M. Rubenstein Senior Fellow for Energy and the Environment Director of the Program on Energy Security and Climate Change

# Hailin Li, Ph.D.

West Virginia University

Assistant Professor, Mechanical and Aerospace Engineering

## Anthony Marchese, Ph.D.

Colorado State University

Associate Professor, Department of Mechanical Engineering

# Jim McCarthy

Innovative Environmental Solutions

# Dayle McDermitt, Ph.D.

LI-COR Biosciences

Vice President for Research & Development, Environmental

# **David McKain**

West Virginia University

Supervisory Engineer, Mechanical and Aerospace Engineering

# Kathryn McKain

Harvard University

Graduate Student, School of Engineering and Applied Sciences

#### Jana Milford, J.D., Ph.D.

University of Colorado, Boulder

Professor and Department Chair, Mechanical Engineering

# Jennifer Miskimins, Ph.D., P.E.

Colorado School of Mines

Associate Professor, Petroleum Engineering

# Maria Obiminda Cambaliza, Ph.D.

**Purdue University** 

Post-Doctoral Staff

# Diane Pataki, Ph.D.

University of California, Irvine

Associate Professor, Earth System Science and Ecology & Evolutionary Biology

Director, Center for Environmental Biology

#### Gabrielle Pétron

National Oceanic and Atmospheric Administration (NOAA)

University of Colorado at Boulder

Earth Systems Research Laboratory Associate Scientist

# Nathan Phillips, Ph.D.

**Boston University** 

Professor, Department of Earth and Environment

Acting Director of the Sustainable Neighborhood Lab

# **David Picard**

Clearstone Engineering Principal

#### **Charles Powars**

St. Croix Research Principal

# Kuldeep Prasad, Ph.D.

National Institute of Standards and Technology (NIST) Mechanical Engineer

# Chris Rella, Ph.D.

Picarro

Research Fellow

# Allen Robinson, Ph.D.

Carnegie Mellon University
Raymond J Lane Distinguished Professor, Mechanical Engineering

#### Melanie Sattler, P.E.

University of Texas at Arlington
Associate Professor, Department of Civil Engineering

# Robert F. Sawyer, Ph.D.

University of California, Berkeley Class of 1935 Professor of Energy Emeritus Professor of the Graduate School Senior Research Engineer, Lawrence Berkeley National Laboratory

# John H. Seinfeld, Ph.D.

California Institute of Technology Louis E. Nohl Professor Professor of Chemical Engineering

# Paul B. Shepson, Ph.D.

Purdue University
Professor, Analytical and Atmospheric Chemistry

# Isobel Simpson, Ph.D.

University of California, Irvine Associate Research Specialist, Atmospheric Chemistry

# R Subramanian, Ph.D.

#### Carnegie Mellon University

# David Sullivan, Ph.D.

University of Texas at Austin

Research Associate. Center for Energy and Environmental Resources

# Colm Sweeney, Ph.D.

National Oceanic and Atmospheric Administration (NOAA) University of Colorado at Boulder Lead Scientist, Earth System Research Lab Aircraft Program

# Robert Talbot, Ph.D.

University of Houston Director of Institute for Climate and Atmospheric Science Professor, Atmospheric Chemistry

# Pieter Tans, Ph.D.

National Oceanic and Atmospheric Administration (NOAA) University of Colorado at Boulder Senior Scientist, Climate Monitoring and Diagnostics Laboratory

## Eben Thoma, Ph.D.

US Environmental Protection Agency (EPA)
Research Environmental Scientist

# Vincent Torres, M.S.

University of Texas at Austin
Associate Director, Center for Energy and Environmental Resources

# Amy Townsend-Small, Ph.D.

University of Cincinnati
Assistant Professor Biogeochemistry, Departments of Geology and Geography

# Joseph Von Fischer, Ph.D.

Colorado State University
Associate Professor, Department of Biology

# Scott Wayne, Ph.D.

West Virginia University
Associate Professor, Mechanical and Aerospace Engineering

# Mike Whelan, M.B.A.

Pipeline Research Council Director, Research Operations

# James Whetstone

National Institute of Standards and Technology (NIST)
Special Assistant to the Director for Greenhouse Gas and Climate Science Measurements

# Bryan Willson, Ph.D.

Colorado State University
Professor of Mechanical Engineering
Founder and Co-director, Engines and Energy Conversion Lab
Program Director, Advanced Research Projects Agency-Energy (ARPA-E)

# Steven Wofsy, Ph.D.

Harvard University
Abbott Lawrence Rotch Professor of Atmospheric and Environmental Science
Associate of Harvard Forest
Area Dean for Environmental Science & Engineering

# Liukang Xu, Ph.D.

LI-COR Biosciences Principal Scientist

# Dan Zimmerle, MSME

Colorado State University
Power Systems Research and Development Manager

# Mark Zondlo, Ph.D.

Princeton University
Assistant Professor, Civil and Environmental Engineering

# <u>List of Project and Researchers Involved in EDF's Efforts To Measure Methane</u> <u>Leakage Across the Natural Gas Industry</u>

PROJECT Production		RESEARCHERS and SCIENTIFIC ADVISORY PANEL MEMBERS
1. UT Phase 1		David Allen, University of Texas
		Vincent Torres, University of Texas
		David Sullivan, University of Texas
		Matthew Harrison, URS
		Al Hendler, URS
		Scott Herndon, Aerodyne,
		Charles Kolb, Aerdoyne
		Matthew Fraser, Arizona State University
		Daniel Hill, Texas A&M University
		Brian Lamb, Washington State University
		Jennifer Miskimins, Colorado School of Mines
		Robert F. Sawyer, University of California, Berkeley
		John H. Seinfeld, California Institute of Technology
2.	UT Phase 2	Same as above
3.	CU Boulder/NOAA	Gabrielle Pétron, University of Colorado, Boulder and National Oceanic (CU Boulder)
	DJ flights	and National Atmospheric Administration, Earth System Research Laboratory
		(NOAA)
		Anna Karion, CU Boulder and NOAA
		Colm Sweeney, CU Boulder and NOAA
		Pieter Tans, NOAA
4. CU Boulder/NOAA		Same as above
_	Barnett flights	Di G III I AI ID I G I
5.	HARC/EPA analysis	Birnur Guven, Houston Advanced Research Center      The State of
		Eben Thoma, EPA
Local		
6.	Multi-city	Brian Lamb, Washington State University
		Tom Ferrara, Conestoga Rovers and Associates
		Touche Howard, Conestoga Rovers and Associates
		Steve Edburg, Washington State University
		Diane Pataki, UC Irvine
		Amy Townsend-Small, University of Cincinnati
		James Whetstone, NIST
		Chuck Colb, Aerodyne

		Matt Harrison, URS
7.	Boston Phase 2	Steve Wofsy, Harvard
		Rob Jackson, Duke
		Nathan Phillips, Boston University
		Adrian Down, Duke
		Lucy Hutyra, BU
		Kathryn McKain, Harvard
8.	Indianapolis	James Whetstone, NIST
		Kuldeep Prasad, NIST
		Maria Obiminda Cambaliza, Purdue
		Kuldeep Prasad, NIST
		Brian Lamb, Washington State University
		Tom Ferrara, Conestoga Rovers and Associates
		Touche Howard, Conestoga Rovers and Associates
		Steve Edburg, Washington State University
9.	Mapping	Joe Von Fischer, Colorado State University
		Jessica Salo, Colorado State University
		Claire Griebenow, Colorado State University
		Linde Bischak, Colorado State University
		Daniel Cooley, Colorado State University
		Jay Ham, Colorado State University
		Russ Schumacher ,Colorado State University
10.	Pump to Wheels	Nigel Clark, West Virginia University
		Derek Johnson, West Virginia University
		Scott Wayne, West Virginia University
		Dave McKain, West Virginia University
		Dave Allen, University of Texas
		Robert "Bob" Sawyer, UC Berkely
		Brent Bailey, NREL
		David Kittelson, University of Minnesota
		Charles Powars, St. Croix Research
11.	Transmission and	Byran Willson, Colorado State University
	Storage	Dan Zimmerle, Colorado State University
		Allen Robinson, Carnegie Mellon University
		R Subramanian, Carnegie Mellon University
		Jeff Kuo, Calstate Fullerton
		David Picard, Clearstone Engineering

		Mile Wheles Disaline December Council
		Mike Whelan, Pipeline Research Council
		Robert Talbot, UH Department of Earth and Atmospheric Sciences
12.	Gathering and	Byran Willson, Colorado State University
	Processing	Anthony Marchese, Colorado State University
		Dan Zimmerle, Colorado State University
		Allen Robinson, Carnegie Mellon University
		R Subramanian, Carnegie Mellon University
13.	Coordinated	Gabrielle Pétron, CU Boulder and NOAA
	Campaign	Anna Karion, CU Boulder and NOAA
		Colm Sweeney, CU Boulder and NOAA
		Paul Shepson, Purdue
		Bob Talbot, University of Houston
		Patrick Laine, University of Houston
		Nigel Clark, West Virginia University
		Derek Johnson, West Virginia University
		Dave McKain, West Virginia University
		Rob Jackson, Duke
		Nathan Phillips, Boston University
		Desiree Plata, Duke
		Don Blake, UC-Irvine
		Amy Townsend-Small, University of Cincinnati
		Isobel Simpson, UC-Irvine
		Mark Zondlo, Princeton
		David Lary, UT-Dallas
		Eric Crosson, Picarro
		Chris Rella, Picarro
		Dayle McDermitt, LI-COR
		George Burba, LI-COR
		Liukang Xu, LI-COR
		Ken Davis, Penn State University
14.	Pipes top-down	
	racts not yet in place)	
15.	Synthesis	
	racts not yet in place)	
16.	Pilot Projects  Boston Phase 1	Steve Wofsy, Harvard
c	i. DOSCOIL FIIASE I	
		·
		Nathan Phillips, Boston University  Kathama Markain Hamanda
		Kathryn McKain, Harvard

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b. UT Arlington drive around	Melane Sattler, University of Texas Arlington
c. CU Boulder drive around and sensor development	<ul> <li>Jana Milford, University of Colorado, Boulder</li> <li>Mike Hannigan, University of Colorado, Boulder</li> </ul>

To: David Lyon[dlyon@edf.org]; amy.townsend-small@uc.edu[amy.townsend-small@uc.edu]; anna.karion@noaa.gov[anna.karion@noaa.gov]; Anthony O'Brien[anthonyo@princeton.edu]; Bill Hirst[bill.hirst@shell.com]; Birnur Guven[bguven@harc.edu]; Brian Lamb[blamb@wsu.edu]; Brian Nathan [brian.nathan@utdallas.edu]; Charles Boller[cboller@craworld.com]; Chris Rella[rella@picarro.com]; Clark, Nigel[Nigel.Clark@mail.wvu.edu]; Colm Sweeney[colm.sweeney@noaa.gov]; Darrell Anderson[anddarrell@gmail.com]; Dave Schaefer[captdaveschaefer@gmail.com]; David Steele[dsteele@picarro.com]; david.lary@utdallas.edu[david.lary@utdallas.edu]; 'Derek Johnson'[Derek.Johnson@mail.wvu.edu]; 'desiree.plata@duke.edu'['desiree.plata@duke.edu']; Don Blake[drblake@uci.edu]; Drew Nelson[dnelson@edf.org]; Thoma, Eben[Thoma.Eben@epa.gov]; ecrosson@picarro.com[ecrosson@picarro.com]; Eric Kort[eakort@umich.edu]; 'Gabrielle Petron - NOAA Affiliate'[gabrielle.petron@noaa.gov]; Brantley, Halley[Brantley.Halley@epa.gov]; Isobel Simpson[isimpson@uci.edu]; 'Jackson@duke.edu'['Jackson@duke.edu']; 'Joe.von\_Fischer@colostate.edu'['Joe.von\_Fischer@colostate.edu']; Josette Marrero[jmarrero@uci.edu]; Kelsey Monk[kmonk@edf.org]; Ken Davis[kjd10@psu.edu]; lanxin.lindsay@gmail.com[lanxin.lindsay@gmail.com]; Malcolm Argyle[argyle@sgl.com]; mcambali@purdue.edu[mcambali@purdue.edu]; McKain, David[David.McKain@mail.wvu.edu]; Morgan Gallagher[morgan.gallagher@duke.edu]; mzondlo@princeton.edu[mzondlo@princeton.edu]; 'plaine@uh.edu'['plaine@uh.edu']; 'pshepson@purdue.edu'['pshepson@purdue.edu']; Ramon Alvarez[RAlvarez@edf.org]; Rob Bennett[robert.bennett@atmosenergy.com]; Sol Meyer[sgltexas@sgl.com]; Steve Conley[sconley@scientificaviation.com]; Steve Edburg[sedburg@wsu.edu]; Steven Hamburg[shamburg@edf.org]; Talbot, Robert[rtalbot@Central.UH.EDU]; Tegan Lavoie[tlavoie@purdue.edu]; Thomas Lauvaux[thomas.lauvaux@carbonnowcast.com]; Tom Ferrara[tferrara@craworld.com]; Touche Howard[touche\_howard@earthlink.net]; Tracy Tsai[ttsai@picarro.com]

From: Robert Harriss

Sent: Thur 2/27/2014 11:58:17 PM

Subject: RE: Barnett Campaign preliminary reports

Hooray for Amy, Josette, Isobel, and Don!

Excellent review of the data status and preliminary science plans. You set a high standard.

Bob

From: David Lyon

Sent: Thursday, February 27, 2014 4:38 PM

To: amy.townsend-small@uc.edu; anna.karion@noaa.gov; Anthony O'Brien; Bill Hirst; Birnur Guven; Brian Lamb; Brian Nathan; Charles Boller; Chris Rella; Clark, Nigel; Colm Sweeney; Darrell Anderson; Dave Schaefer; David Steele; david.lary@utdallas.edu; 'Derek Johnson'; 'desiree.plata@duke.edu'; Don Blake; Drew Nelson; Eben Thoma; ecrosson@picarro.com; Eric Kort; 'Gabrielle Petron - NOAA Affiliate'; Halley Brantley; Isobel Simpson; 'Jackson@duke.edu'; 'Joe.von Fischer@colostate.edu'; Josette Marrero; Kelsey Monk; Ken Davis; lanxin.lindsay@gmail.com; Malcolm Argyle; mcambali@purdue.edu; McKain, David; Morgan Gallagher; mzondlo@princeton.edu; 'plaine@uh.edu'; 'pshepson@purdue.edu'; Ramon Alvarez; Rob Bennett; Robert Harriss; Sol Meyer; Steve Conley; Steve Edburg; Steven Hamburg; Talbot, Robert; Tegan Lavoie; Thomas Lauvaux; Tom Ferrara; Touche Howard; Tracy Tsai

Subject: Barnett Campaign preliminary reports

Thanks to Amy for submitting the first Barnett Campaign preliminary report! I hope everyone is making progress on their own reports. As a reminder, the reports can be submitted as either a document or PowerPoint presentation and should address the following questions:

- What are your preliminary high-level conclusions?
- What is the status of your data?
- o samples analyzed and QA/QC
- o format for reporting/sharing (units, uncertainties, spatial & temporal scale, etc.)
- o expected date to distribute data to collaborators
- o any concerns related to specific data
- o any unresolved confidentiality issues (e.g. identity of sites where a company gave you permission to sample)
- What manuscripts do you expect to write from your own data?
- Which teams are you collaborating with or have an interest in collaborating?
- o What data needs to be shared among teams?
- o What are potential manuscripts that can be written by collaborating teams?
- How do you think your data can be used in the synthesis?
- What additional work do you expect to perform for the final report?

The reports are technically due on March 1, but since that is a Saturday feel free to turn them in on Monday, March 3. You can email me the report if it is less than 10 Mb, but otherwise please upload it to the Dropbox "Preliminary Reports" folder at the link below:

https://www.dropbox.com/sh/k6wdglqop06dkyp/FlNA45mLGq

Thanks,

David

[cid:image001.jpg@01CF33E2.8F7AF820]

David Lyon

Research Analyst

Environmental Defense Fund 301 Congress Avenue, Suite 1300 Austin, TX 78701 (512) 691-3414 dlyon@edf.org<mailto:dlyon@edf.org>

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To: amy.townsend-small@uc.edu[amy.townsend-small@uc.edu]; anna.karion@noaa.gov[anna.karion@noaa.gov]; Anthony O'Brien[anthonyo@princeton.edu]; Bill Hirst[bill.hirst@shell.com]; Birnur Guven[bguven@harc.edu]; Brian Lamb[blamb@wsu.edu]; Brian Nathan [brian.nathan@utdallas.edu]; Charles Boller[cboller@craworld.com]; Chris Rella[rella@picarro.com]; Clark, Nigel[Nigel.Clark@mail.wvu.edu]; Colm Sweeney[colm.sweeney@noaa.gov]; Darrell Anderson[anddarrell@gmail.com]; Dave Schaefer[captdaveschaefer@gmail.com]; David Steele[dsteele@picarro.com]; david.lary@utdallas.edu[david.lary@utdallas.edu]; 'Derek Johnson'[Derek.Johnson@mail.wvu.edu]; 'desiree.plata@duke.edu'['desiree.plata@duke.edu']; Don Blake[drblake@uci.edu]; Drew Nelson[dnelson@edf.org]; Thoma, Eben[Thoma.Eben@epa.gov]; ecrosson@picarro.com[ecrosson@picarro.com]; Eric Kort[eakort@umich.edu]; 'Gabrielle Petron - NOAA Affiliate'[gabrielle.petron@noaa.gov]; Brantley, Halley[Brantley.Halley@epa.gov]; Isobel Simpson[isimpson@uci.edu]; 'Jackson@duke.edu'['Jackson@duke.edu']; 'Joe.von\_Fischer@colostate.edu'['Joe.von\_Fischer@colostate.edu']; Josette Marrero[jmarrero@uci.edu]; Kelsey Monk[kmonk@edf.org]; Ken Davis[kjd10@psu.edu]; lanxin.lindsay@gmail.com[lanxin.lindsay@gmail.com]; Malcolm Argyle[argyle@sgl.com]; mcambali@purdue.edu[mcambali@purdue.edu]; McKain, David[David.McKain@mail.wvu.edu]; Morgan Gallagher[morgan.gallagher@duke.edu]; mzondlo@princeton.edu[mzondlo@princeton.edu]; 'plaine@uh.edu'['plaine@uh.edu']; 'pshepson@purdue.edu'['pshepson@purdue.edu']; Ramon Alvarez[RAlvarez@edf.org]; Rob Bennett[robert.bennett@atmosenergy.com]; Robert Harriss[rharriss@edf.org]; Sol Meyer[sgltexas@sgl.com]; Steve Conley[sconley@scientificaviation.com]; Steve Edburg[sedburg@wsu.edu]; Steven Hamburg[shamburg@edf.org]; Talbot, Robert[rtalbot@Central.UH.EDU]; Tegan Lavoie[tlavoie@purdue.edu]; Thomas Lauvaux[thomas.lauvaux@carbonnowcast.com]; Tom Ferrara[tferrara@craworld.com]; Touche Howard[touche\_howard@earthlink.net]; Tracy Tsai[ttsai@picarro.com] David Lyon From:

Sent: Thur 2/27/2014 11:38:44 PM

Subject: Barnett Campaign preliminary reports

Thanks to Amy for submitting the first Barnett Campaign preliminary report! I hope everyone is making progress on their own reports. As a reminder, the reports can be submitted as either a document or PowerPoint presentation and should address the following questions:

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- What is the status of your data?
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- o any unresolved confidentiality issues (e.g. identity of sites where a company gave you permission to sample)

- What manuscripts do you expect to write from your own data?
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https://www.dropbox.com/sh/k6wdglqop06dkyp/FlNA45mLGq

Thanks,

David

MANAGE.

David Lyon

Research Analyst

**Environmental Defense Fund** 301 Congress Avenue, Suite 1300

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For further information, please contact the EPA Call Center at (866) 411-4EPA (4372). The TDD number is (866) 489-4900.

To: amy.townsend-small@uc.edu[amy.townsend-small@uc.edu]; anna.karion@noaa.gov[anna.karion@noaa.gov]; Anthony O'Brien[anthonyo@princeton.edu]; Bill Hirst[bill.hirst@shell.com]; Birnur Guven[bguven@harc.edu]; Brian Lamb[blamb@wsu.edu]; Brian Nathan [brian.nathan@utdallas.edu]; Charles Boller[cboller@craworld.com]; Chris Rella[rella@picarro.com]; Clark, Nigel[Nigel.Clark@mail.wvu.edu]; Colm Sweeney[colm.sweeney@noaa.gov]; Darrell Anderson[anddarrell@gmail.com]; Dave Schaefer[captdaveschaefer@gmail.com]; David Steele[dsteele@picarro.com]; david.lary@utdallas.edu[david.lary@utdallas.edu]; 'Derek Johnson'[Derek.Johnson@mail.wvu.edu]; 'desiree.plata@duke.edu'['desiree.plata@duke.edu']; Don Blake[drblake@uci.edu]; Drew Nelson[dnelson@edf.org]; Thoma, Eben[Thoma.Eben@epa.gov]; ecrosson@picarro.com[ecrosson@picarro.com]; Eric Kort[eakort@umich.edu]; 'Gabrielle Petron - NOAA Affiliate'[gabrielle.petron@noaa.gov]; Brantley, Halley[Brantley.Halley@epa.gov]; Isobel Simpson[isimpson@uci.edu]; 'Jackson@duke.edu'['Jackson@duke.edu']; 'Joe.von\_Fischer@colostate.edu'['Joe.von\_Fischer@colostate.edu']; Josette Marrero[jmarrero@uci.edu]; Kelsey Monk[kmonk@edf.org]; Ken Davis[kjd10@psu.edu]; lanxin.lindsay@gmail.com[lanxin.lindsay@gmail.com]; Malcolm Argyle[argyle@sgl.com]; mcambali@purdue.edu[mcambali@purdue.edu]; McKain, David[David.McKain@mail.wvu.edu]; Morgan Gallagher[morgan.gallagher@duke.edu]; mzondlo@princeton.edu[mzondlo@princeton.edu]; 'plaine@uh.edu'['plaine@uh.edu']; 'pshepson@purdue.edu'['pshepson@purdue.edu']; Ramon Alvarez[RAlvarez@edf.org]; Rob Bennett[robert.bennett@atmosenergy.com]; Robert Harriss[rharriss@edf.org]; Sol Meyer[sgltexas@sgl.com]; Steve Conley[sconley@scientificaviation.com]; Steve Edburg[sedburg@wsu.edu]; Steven Hamburg[shamburg@edf.org]; Talbot, Robert[rtalbot@Central.UH.EDU]; Tegan Lavoie[tlavoie@purdue.edu]; Thomas Lauvaux[thomas.lauvaux@carbonnowcast.com]; Tom Ferrara[tferrara@craworld.com]; Touche Howard[touche\_howard@earthlink.net]; Tracy Tsai[ttsai@picarro.com]; Daniel Jacob[djacob@fas.harvard.edu]; Doug Blewitt[dougblewitt@comcast.net]; Francis O'Sullivan[frankie@mit.edu]; Steve Hanna[hannaconsult@roadrunner.com] From: David Lyon

Sent: Tue 1/21/2014 11:20:38 PM

Subject: Barnett campaign workshop agenda Barnett Campaign Workshop Agenda.docx

# Greetings,

I have attached a draft agenda for the Barnett Campaign workshop. It also includes information on the complimentary hotel shuttle, which picks people up at the airport on the hour and halfhour. On Thursday, we will have boxed lunches available at noon and commence the meeting at 1:00 PM. For Thursday dinner and Friday breakfast and lunch, the hotel will set up meals in the meeting room so we can maximize our meeting time. We will adjourn by 4:00 PM Friday so people can make their return flights.

Tomorrow I will send more information about the meeting room and instructions for joining by phone and web conference. Please let me know if you have any questions.

Safe travels,
David
David Lyon
Research Analyst
Environmental Defense Fund 301 Congress Avenue, Suite 1300
Austin, TX 78701 (512) 691-3414 <u>dlyon@edf.org</u>
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To: amy.townsend-small@uc.edu[amy.townsend-small@uc.edu]; anna.karion@noaa.gov[anna.karion@noaa.gov]; Anthony O'Brien[anthonyo@princeton.edu]; Bill Hirst[bill.hirst@shell.com]; Birnur Guven[bguven@harc.edu]; Brian Lamb[blamb@wsu.edu]; Brian Nathan [brian.nathan@utdallas.edu]; Charles Boller[cboller@craworld.com]; Chris Rella[rella@picarro.com]; Clark, Nigel[Nigel.Clark@mail.wvu.edu]; Colm Sweeney[colm.sweeney@noaa.gov]; Darrell Anderson[anddarrell@gmail.com]; Dave Schaefer[captdaveschaefer@gmail.com]; David Steele[dsteele@picarro.com]; david.lary@utdallas.edu[david.lary@utdallas.edu]; 'Derek Johnson'[Derek.Johnson@mail.wvu.edu]; 'desiree.plata@duke.edu'['desiree.plata@duke.edu']; Don Blake[drblake@uci.edu]; Drew Nelson[dnelson@edf.org]; Thoma, Eben[Thoma.Eben@epa.gov]; ecrosson@picarro.com[ecrosson@picarro.com]; Eric Kort[eakort@umich.edu]; 'Gabrielle Petron - NOAA Affiliate'[gabrielle.petron@noaa.gov]; Brantley, Halley[Brantley.Halley@epa.gov]; Isobel Simpson[isimpson@uci.edu]; 'Jackson@duke.edu'['Jackson@duke.edu']; 'Joe.von\_Fischer@colostate.edu'['Joe.von\_Fischer@colostate.edu']; Josette Marrero[jmarrero@uci.edu]; Kelsey Monk[kmonk@edf.org]; Ken Davis[kjd10@psu.edu]; lanxin.lindsay@gmail.com[lanxin.lindsay@gmail.com]; Malcolm Argyle[argyle@sgl.com]; mcambali@purdue.edu[mcambali@purdue.edu]; McKain, David[David.McKain@mail.wvu.edu]; Morgan Gallagher[morgan.gallagher@duke.edu]; mzondlo@princeton.edu[mzondlo@princeton.edu]; 'plaine@uh.edu'['plaine@uh.edu']; 'pshepson@purdue.edu'['pshepson@purdue.edu']; Ramon Alvarez[RAlvarez@edf.org]; Rob Bennett[robert.bennett@atmosenergy.com]; Robert Harriss[rharriss@edf.org]; Sol Meyer[sgltexas@sgl.com]; Steve Conley[sconley@scientificaviation.com]; Steve Edburg[sedburg@wsu.edu]; Steven Hamburg[shamburg@edf.org]; Talbot, Robert[rtalbot@Central.UH.EDU]; Tegan Lavoie[tlavoie@purdue.edu]; Thomas Lauvaux[thomas.lauvaux@carbonnowcast.com]; Tom Ferrara[tferrara@craworld.com]; Touche Howard[touche\_howard@earthlink.net]; Tracy Tsai[ttsai@picarro.com]; Daniel Jacob[djacob@fas.harvard.edu]; Doug Blewitt[dougblewitt@comcast.net]; Francis O'Sullivan[frankie@mit.edu]; Steve Hanna[hannaconsult@roadrunner.com]

Cc: Lucy Kalunde[lkalunde@edf.org]

From: David Lyon

**Sent:** Wed 1/15/2014 10:31:38 PM

Subject: Barnett campaign workshop presentations

# Greetings,

I look forward to seeing everyone on January 23 & 24 for the Barnett campaign workshop at the Denver Airport Marriott at Gateway Park. If you plan on attending and have not yet submitted your information to Lucy (<a href="mailto:lkalunde@edf.org">lkalunde@edf.org</a>), then please do so as soon as possible so she can book your flight and room. We are arranging a teleconference if you would like to participate remotely.

We currently are planning the agenda for the meeting. On Thursday afternoon, we would like each research team to give a 15 minute presentation that includes the following information: 1) what worked and what did not work in your research, 2) results to date & 3) schedule of forthcoming results. On Thursday evening, we may arrange a dinner to allow group discussions on integrative approaches to key questions. On Friday, the focus will be on outlining papers and

planning for the campaign synthesis, including arranging data sharing and future face-to-face
meetings. Please let me know if you have ideas for specific topics we should cover during the
meeting.

Thanks,

David

MARKET NA

David Lyon

Research Analyst

**Environmental Defense Fund** 301 Congress Avenue, Suite 1300

Austin, TX 78701 (512) 691-3414 dlyon@edf.org

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receiving the revised Email, containing the renamed attachment, you can rename the file extension to its correct name.

For further information, please contact the EPA Call Center at  $(866)\ 411-4$ EPA (4372). The TDD number is  $(866)\ 489-4900$ .

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To: Steven Hamburg[shamburg@edf.org]; allen@che.utexas.edu[allen@che.utexas.edu]; matt.harrison@urs.com[]; Herndon@aerodyne.com[] Herndon@aerodyne.com[]; matt.harrison@urs.com[]; Herndon@aerodyne.com[]; matt.harrison@urs.com[]; Herndon@aerodyne.com[]; colm.sweeney@noaa.gov[gabrielle.petron@noaa.gov]; anna.karion@noaa.gov[anna.karion@noaa.gov]; bguven@harc.edu[bguven@harc.edu]; Thoma, Eben[Thoma.Eben@epa.gov]; bguven@harc.edu[bguven@harc.edu]; thoma, Eben[Thoma.Eben@epa.gov]; bguven@harc.edu[swsu.edu]; thoma, Eben[Thoma.Eben@epa.gov]; bguven@harc.edu[swsu.edu]; thoma, Eben[Thoma.Eben@epa.gov]; bguven@raworld.com]; sedburg@wsu.edu[] sedburg@wsu.edu]; toward@craworld.com[toward@craworld.com]; sedburg@wsu.edu[]; sedburg@wsu.edu]; pathan@bu.edu[]; jackson@duke.edu]; pathan@bu.edu[]; jackson@duke.edu]; pathan@bu.edu[]; jackson@duke.edu]; swofsy@seas.harvard.edu[]; swofsy@seas.harvard.edu]; swofs
All
Attached is the final list that includes edits suggested in the responses folks provided to Steve last week. This list will go public at 3 eastern. If you have any additional edits, please send those to me in the next 30 minutes (or sooner).
Thanks
Drew

From: Steven Hamburg

Sent: Thursday, September 12, 2013 7:30 AM

To: allen@che.utexas.edu; matt.harrison@urs.com; Herndon@aerodyne.com; colm.sweeney@noaa.gov; gabrielle.petron@noaa.gov; anna.karion@noaa.gov; bguven@harc.edu; Thoma.eben@epamail.epa.gov; blamb@wsu.edu; tferrara@craworld.com; sedburg@wsu.edu; toward@craworld.com; james.whetstone@nist.gov; pshepson@purdue.edu; nathan@bu.edu; jackson@duke.edu; swofsy@seas.harvard.edu; kmckain@seas.harvard.edu; Joe.von\_Fischer@colostate.edu; Nigel.Clark@mail.wvu.edu; Bryan.Willson@ColoState.EDU; Dan.Zimmerle@ColoState.EDU; alr@andrew.cmu.edu; subu@cmu.edu; Anthony.Marchese@ColoState.EDU; amy.townsend-small@uc.edu; rella@picarro.com; david.lary@utdallas.edu; dayle.mcdermitt@licor.com; Derek.Johnson@mail.wvu.edu; desiree.plata@duke.edu; drblake@uci.edu; ecrosson@picarro.com; george.burba@licor.com; isimpson@uci.edu; kjd10@psu.edu; Liukang.xu@licor.com; David.McKain@mail.wvu.edu; msp. Pabet Harrisos Lauran Miritanbara.

Cc: Drew Nelson; Ramon Alvarez; Robert Harriss; Lauren Whittenberg

**Subject:** Requesting a favor - making public the list of methane projects and scientific participants

Importance: High

. Dear Scientific Collaborators

As you may be aware, on Monday the 16<sup>th</sup> PNAS will be publishing the University of Texas' manuscript on methane leakage from the production sector. This paper will release the results of the first of the many studies that those on this e-mail are conducting as part of the larger effort EDF is helping to catalyze. We anticipate that this first study will receive significant press attention. As part of the study rollout, EDF would like to illustrate the breadth and scope of the overall effort by listing all of the projects and scientific collaborators that we are working with across the various studies. To that end, we have prepared the attached document listing the projects and collaborators. Please take a look and let me know, if at all possible in the next day, if you are not comfortable with having your name and project included on the list. Please note that not every name on this list is included in this email. I would appreciate it if PIs could check to make sure the names of their teams are listed correctly.

Thanks for all of your hard work towards helping the science and policy communities to better understand methane leakage from the natural gas supply chain. I look forward to having all of your work out and published over the coming months.

Cheers

Steve

Steven Hamburg

Chief Scientist
Environmental Defense Fund
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FOIA EPA-HQ-2018-0005849

ED\_001785C\_00000693-00003

To: Thoma, Eben[Thoma.Eben@epa.gov]

Cc: Lucy Kalunde[lkalunde@edf.org]; Kelsey Monk[kmonk@edf.org]

From: David Lyon

**Sent:** Wed 1/8/2014 3:29:18 PM

Subject: RE: Barnett Campaign meeting January 23 & 24 in Denver

Eben,

Yes, EDF will pay for Halley Brantley's attendance to the Denver meeting if EPA can cover your expenses. We look forward to both of your participation in the workshop.

Please have Halley send the following information to Lucy Kalunde (<u>lkalunde@edf.org</u>).

- 1. Name (First, Middle, Last)
- 2. DOB
- 3. Preferred Contact Phone #
- 4. Preferred Airport (realize some people may be travelling already)
- 5. Any other important info we'll need to book a good flight for them.

Best Regards,

David

From: Thoma, Eben [mailto:Thoma.Eben@epa.gov]

Sent: Tuesday, January 07, 2014 6:27 AM

**To:** David Lyon **Cc:** Lucy Kalunde

Subject: RE: Barnett Campaign meeting January 23 & 24 in Denver

Thanks David,

I have a question for you. Our new researcher (Halley Brantley) just started and will be heavily involved in our work together. She basically will be our primarily horsepower here. In my opinion, our collaboration would benefit greatly from her attendance at the Denver workshop.

Unfortunately, we currently don't have a mechanism to pay for her travel. If I can get EPA to pay for my travel to the Denver meeting, Do you think it may be possible for EDF to pay for Halley's trip (just this time)? EDF would still be sponsoring only one person's trip from the EPA team. I understand if this is not possible and frankly, I not sure we have the funds to pay for my trip but it is worth asking.

Thanks.	
---------	--

Eben

From: David Lyon [mailto:dlyon@edf.org]
Sent: Monday, January 06, 2014 3:31 PM

To: Thoma, Eben Cc: Lucy Kalunde

Subject: RE: Barnett Campaign meeting January 23 & 24 in Denver

Eben,

I am glad you can attend our Barnett campaign meeting. The meeting will be at the Marriott Denver Airport at Gateway (16455 E. 40th Circle, Aurora, CO 80011).

David

From: Thoma, Eben [mailto:Thoma.Eben@epa.gov] Sent: Tuesday, December 31, 2013 10:14 AM

To: Lucy Kalunde Cc: David Lyon Subject: FW: Barnett Campaign meeting January 23 & 24 in Denver
Hi Lucy,
Just resending the below email not because I messed-up your address the first time.
It looks like Southwest Airlines is the government contract carrier from RDU to Denver so I should be able to get a pretty good ticket prices through the Government system. I will let you know when I conform the cost.
Also,
I need to know the exact location of the meeting in order to complete our mandatory ethics review from for invited travel. Please let me know the meeting site location and room rates as soon as you can.
Thanks,
Eben
From: Thoma, Eben Sent: Sunday, December 29, 2013 11:03 AM To: David Lyon; Lucy@Kalunde Subject: Re: Barnett Campaign meeting January 23 & 24 in Denver

Hi David and Lucy,

I would like to try to attend. Just to confirm, EDF is offering to reimburse EPA for this as it has done for past meetings in this series (please confirm). This kind offer would be greatly appreciated as our travel budgets are slim at present.

As in the past, I will need to make my own reservations through EPA travel services and EPA will get in touch with EDF after the trip. I would plan on taking Southwest Flt 1030 from RDU arriving at 11:25 AM on 1/23 and I would need to take FLT 2608 departing Denver at 5:00 pm 1/24 so I would need to leave a tad bit early. I can get back to you on the cost of these flts in a couple of days. I am going to try to get the web deal but our travel folks may not allow me to do this.

It may be possible for you to book the flts for me at the web fare but this is a little complicated and will (as with the trip) need to go through the EPA ethics review process. This will take some time and I will get back to you as soon as I know something.

Let me now if this generally sound okay and sorry for the extra bother.

Thanks,

Eben

From: David Lyon <a href="mailto:square">dlyon@edf.org</a>

**Sent:** Thursday, December 19, 2013 4:49:46 PM

To: Thoma, Eben; Birnur Guven (<a href="mailto:bguven@harcresearch.org">bguven@harcresearch.org</a>); Natalie Pekney; <a href="mailto:amy.townsend-small@uc.edu">amy.townsend-small@uc.edu</a>; <a href="mailto:amy.amy.townsend-small@uc.edu">anna.karion@noaa.gov</a>; Anthony O'Brien; Bill Hirst; Brian Lamb; Brian Nathan; Charles Boller; Chris Rella; Clark, Nigel; Colm Sweeney; Darrell Anderson; Dave Schaefer; David Steele; <a href="mailto:david.lary@utdallas.edu">david.lary@utdallas.edu</a>; 'Derek Johnson'; 'desiree.plata@duke.edu'; Don Blake; Drew Nelson; <a href="mailto:ecrosson@picarro.com">ecrosson@picarro.com</a>; Eric Kort; 'Gabrielle Petron - NOAA Affiliate'; Isobel Simpson; 'Jackson@duke.edu'; 'Joe.von\_Fischer@colostate.edu'; Josette Marrero; Kelsey Monk; Ken Davis; <a href="mailto:lanxin.lindsay@gmail.com">lanxin.lindsay@gmail.com</a>; Malcolm Argyle; <a href="mailto:mcambali@purdue.edu">mcambali@purdue.edu</a>; McKain, David; Morgan Gallagher; <a href="mailto:mzondlo@princeton.edu">mzondlo@princeton.edu</a>; 'plaine@uh.edu'; 'pshepson@purdue.edu'; Ramon Alvarez; Rob Bennett; Robert Harriss; Sol Meyer; Steve Conley; Steve Edburg; Talbot, Robert; Tegan Lavoie; Thomas Lauvaux; Tom Ferrara; Touche Howard; Tracy Tsai; Daniel Jacob; Doug Blewitt; Francis O'Sullivan; Steve Hanna

Cc: Lucy Kalunde; Kelsey Monk

Subject: Barnett Campaign meeting January 23 & 24 in Denver

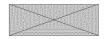
Greetings,

The Barnett Campaign meeting will be January 23 & 24 in Denver. Yes, I'm aware that Denver is cold in January, but it is the most convenient location to bring people together. EDF will book a block of rooms and meeting place at a hotel near the Denver International Airport. We plan on starting the meeting around 1:00 pm Thursday and ending around 4:00 pm Friday, which should allow most people to stay only one night at the hotel. Lucy Kalunde at EDF will book your flights. Please let us know if you are attending and send Lucy (<a href="mailto:lkalunde@edf.org">lkalunde@edf.org</a>) the following information as soon as possible.

- 1. Name (First, Middle, Last)
- 2. DOB
- 3. Preferred Contact Phone #
- 4. Preferred Airport (realize some people may be travelling already)
- 5. Any other important info we'll need to book a good flight for them.

Thanks,

David



David Lyon

Research Analyst

**Environmental Defense Fund** 301 Congress Avenue, Suite 1300

Austin, TX 78701 (512) 691-3414 dlyon@edf.org

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To: amy.townsend-small@uc.edu[amy.townsend-small@uc.edu]; anna.karion@noaa.gov[anna.karion@noaa.gov]; Anthony O'Brien[anthonyo@princeton.edu]; Bill Hirst[bill.hirst@shell.com]; Birnur Guven[bguven@harc.edu]; Brian Lamb[blamb@wsu.edu]; Brian Nathan [brian.nathan@utdallas.edu]; Charles Boller[cboller@craworld.com]; Chris Rella[rella@picarro.com]; Clark, Nigel[Nigel.Clark@mail.wvu.edu]; Colm Sweeney[colm.sweeney@noaa.gov]; Connor Botkin[cbotkin@picarro.com]; Darrell Anderson[anddarrell@gmail.com]; Dave Schaefer[captdaveschaefer@gmail.com]; David Steele[dsteele@picarro.com]; david.lary@utdallas.edu[david.lary@utdallas.edu]; 'Derek Johnson'[Derek.Johnson@mail.wvu.edu]; 'desiree.plata@duke.edu'['desiree.plata@duke.edu']; Don Blake[drblake@uci.edu]; Drew Nelson[dnelson@edf.org]; Thoma, Eben[Thoma.Eben@epa.gov]; ecrosson@picarro.com[ecrosson@picarro.com]; Eric Kort[eakort@umich.edu]; 'Gabrielle Petron - NOAA Affiliate'[gabrielle.petron@noaa.gov]; Brantley, Halley[Brantley.Halley@epa.gov]; Isobel Simpson[isimpson@uci.edu]; 'Jackson@duke.edu'['Jackson@duke.edu']; 'Joe.von\_Fischer@colostate.edu'['Joe.von\_Fischer@colostate.edu']; Josette Marrero[jmarrero@uci.edu]; Kelsey Monk[kmonk@edf.org]; Ken Davis[kjd10@psu.edu]; lanxin.lindsay@gmail.com[lanxin.lindsay@gmail.com]; Malcolm Argyle[argyle@sgl.com]; mcambali@purdue.edu[mcambali@purdue.edu]; McKain, David[David.McKain@mail.wvu.edu]; Morgan Gallagher[morgan.gallagher@duke.edu]; mzondlo@princeton.edu[mzondlo@princeton.edu]; 'pshepson@purdue.edu'['pshepson@purdue.edu']; Ramon Alvarez[RAlvarez@edf.org]; Rob Bennett[robert.bennett@atmosenergy.com]; Robert Harriss[rharriss@edf.org]; Sol Meyer[sgltexas@sgl.com]; Steve Conley[sconley@scientificaviation.com]; Steve Edburg[sedburg@wsu.edu]; Steven Hamburg[shamburg@edf.org]; Talbot, Robert[rtalbot@Central.UH.EDU]; Tegan Lavoie[tlavoie@purdue.edu]; Thomas Lauvaux[thomas.lauvaux@carbonnowcast.com]; Tom Ferrara[tferrara@craworld.com]; Touche Howard[touche\_howard@earthlink.net]; Tracy Tsai[ttsai@picarro.com]; Daniel Jacob[djacob@fas.harvard.edu]; Doug Blewitt[dougblewitt@comcast.net]; Francis O'Sullivan[frankie@mit.edu]; Steve Hanna[hannaconsult@roadrunner.com]

From: David Lyon

**Sent:** Wed 3/26/2014 7:59:46 PM

Subject: Barnett Campaign April 18 workshop

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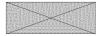
### Greetings,

The next Barnett Campaign workshop will be Friday April 18. Due to scheduling conflicts, NOAA/CU, U. Michigan, and LightTouch are unable to attend this date, so the workshop will focus on integrating the bottom up measurements. We will set up a separate call among the top-down groups to facilitate their collaboration. We are trying to keep this meeting relatively small, so please limit attendance to PI's and others critical to the project.

We have not decided a location yet but will try to finalize it this week. It will likely be near a hub airport to minimize people's travel time. If you plan to attend the workshop, please notify Kelsey Monk (kmonk@edf.org) so we can begin planning travel arrangements.

Thanks,

David



David Lyon

Research Analyst

**Environmental Defense Fund** 301 Congress Avenue, Suite 1300

Austin, TX 78701 (512) 691-3414 <u>dlyon@edf.org</u>

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To: Cc: From: Sent:	Thoma, Eben[Thoma.Eben@epa.gov] Lucy Kalunde[lkalunde@edf.org] David Lyon Mon 1/6/2014 8:30:50 PM  PE: Persett Compaign meeting January 23 8 24 in Deputy	
Subject: Eben,	RE: Barnett Campaign meeting January 23 & 24 in Denver	
	you can attend our Barnett campaign meeting. The meeting will be at the Marriott irport at Gateway (16455 E. 40th Circle, Aurora, CO 80011).	
David		
Sent: Tue To: Lucy h Cc: David		
Hi Lucy,		
Just resen	ding the below email not because I messed-up your address the first time.	
It looks like Southwest Airlines is the government contract carrier from RDU to Denver so I should be able to get a pretty good ticket prices through the Government system. I will let you know when I conform the cost.		
Also,		
	know the exact location of the meeting in order to complete our mandatory ethics om for invited travel. Please let me know the meeting site location and room rates as	

soon as you can.
Thanks,
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From: Thoma, Eben Sent: Sunday, December 29, 2013 11:03 AM To: David Lyon; Lucy@Kalunde Subject: Re: Barnett Campaign meeting January 23 & 24 in Denver
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It may be possible for you to book the flts for me at the web fare but this is a little complicated and will (as with the trip) need to go through the EPA ethics review process. This will take som time and I will get back to you as soon as I know something.
Let me now if this generally sound okay and sorry for the extra bother.
Thanks,
Eben
From: David Lyon <a href="mailto:dlyon@edf.org">dlyon@edf.org</a>

ED\_001785C\_00000817-00002

**Sent:** Thursday, December 19, 2013 4:49:46 PM

To: Thoma, Eben; Birnur Guven (<a href="mailto:bguven@harcresearch.org">bguven@harcresearch.org</a>); Natalie Pekney; <a href="mailto:amy.townsend-small@uc.edu">amy.townsend-small@uc.edu</a>; <a href="mailto:amy.townsend-small@uc.edu">amy.townsend-small@uc.edu</a>; <a href="mailto:amy.amy.townsend-small@uc.edu">amy.townsend-small@uc.edu</a>; <a href="mailto:Brian Nathan">Brian Nathan</a>; <a href="mailto:Charles Boller">Charles Boller</a>; Chris Rella; Clark, Nigel; Colm Sweeney; <a href="mailto:Darrell Anderson">Davrell Anderson</a>; <a href="mailto:Davrell-darrell-d

Cc: Lucy Kalunde; Kelsey Monk

Subject: Barnett Campaign meeting January 23 & 24 in Denver

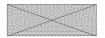
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- 1. Name (First, Middle, Last)
- 2. DOB
- 3. Preferred Contact Phone #
- 4. Preferred Airport (realize some people may be travelling already)
- 5. Any other important info we'll need to book a good flight for them.

Thanks,

David



David Lyon

Research Analyst

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Austin, TX 78701 (512) 691-3414 dlyon@edf.org

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To: amy.townsend-small@uc.edu[amy.townsend-small@uc.edu]; anna.karion@noaa.gov[anna.karion@noaa.gov]; Anthony O'Brien[anthonyo@princeton.edu]; Bill Hirst[bill.hirst@shell.com]; Birnur Guven[bguven@harc.edu]; Brian Lamb[blamb@wsu.edu]; Brian Nathan [brian.nathan@utdallas.edu]; Charles Boller[cboller@craworld.com]; Chris Rella[rella@picarro.com]; Clark, Nigel[Nigel.Clark@mail.wvu.edu]; Colm Sweeney[colm.sweeney@noaa.gov]; Darrell Anderson[anddarrell@gmail.com]; Dave Schaefer[captdaveschaefer@gmail.com]; David Steele[dsteele@picarro.com]; david.lary@utdallas.edu[david.lary@utdallas.edu]; 'Derek Johnson'[Derek.Johnson@mail.wvu.edu]; 'desiree.plata@duke.edu'['desiree.plata@duke.edu']; Don Blake[drblake@uci.edu]; Drew Nelson[dnelson@edf.org]; Thoma, Eben[Thoma.Eben@epa.gov]; ecrosson@picarro.com[ecrosson@picarro.com]; Eric Kort[eakort@umich.edu]; 'Gabrielle Petron - NOAA Affiliate'[gabrielle.petron@noaa.gov]; Brantley, Halley[Brantley.Halley@epa.gov]; Isobel Simpson[isimpson@uci.edu]; 'Jackson@duke.edu'['Jackson@duke.edu']; 'Joe.von\_Fischer@colostate.edu'['Joe.von\_Fischer@colostate.edu']; Josette Marrero[jmarrero@uci.edu]; Kelsey Monk[kmonk@edf.org]; Ken Davis[kjd10@psu.edu]; lanxin.lindsay@gmail.com[lanxin.lindsay@gmail.com]; Malcolm Argyle[argyle@sgl.com]; mcambali@purdue.edu[mcambali@purdue.edu]; McKain, David[David.McKain@mail.wvu.edu]; Morgan Gallagher[morgan.gallagher@duke.edu]; mzondlo@princeton.edu[mzondlo@princeton.edu]; 'plaine@uh.edu'['plaine@uh.edu']; 'pshepson@purdue.edu'['pshepson@purdue.edu']; Ramon Alvarez[RAlvarez@edf.org]; Rob Bennett[robert.bennett@atmosenergy.com]; Robert Harriss[rharriss@edf.org]; Sol Meyer[sgltexas@sgl.com]; Steve Conley[sconley@scientificaviation.com]; Steve Edburg[sedburg@wsu.edu]; Steven Hamburg[shamburg@edf.org]; Talbot, Robert[rtalbot@Central.UH.EDU]; Tegan Lavoie[tlavoie@purdue.edu]; Thomas Lauvaux[thomas.lauvaux@carbonnowcast.com]; Tom Ferrara[tferrara@craworld.com]; Touche Howard[touche\_howard@earthlink.net]; Tracy Tsai[ttsai@picarro.com] Cc: Kelsey Robinson[krobinson@edf.org]

From: David Lyon

Sent: Mon 2/24/2014 3:37:43 PM Subject: Barnett campaign video footage

I'm pleased to share with you the usable video footage that was collected during the Barnett Campaign. We hope you will find this to be a useful resource to communicate about the project.

To access the videos, click the links below and enter the password "Methane". An index is included below to allow you to focus on the portion of the videos of interest to you.

We also want to confirm your consent for EDF to use a portion of the footage for educational and development uses, including EDF blog or YouTube posts. Please email Kelsey Robinson by February 28 with a response acknowledging this request. Additionally, we ask that you please notify EDF and offer us a chance to review any video footage intended for commercial purposes before it is published.

You may note that we have blurred out the logo of the company partner.

ED 001785C 00000848-00001

# <u>Barnett Coordinated Campaign Video Timeline—Day One</u> (Password = Methane)

•□□□□□□ 0:00-0:49	Full group morning meeting
• • • • • • • • • • • • • • • • • • • •	Compressor station measurements, West Virginia University
•□□□□□□□ 3:22-9:34	David McKain, West Virginia University
•□□□□□□□ 9:36-12:38	Remote controlled model aircraft team, UT-Dallas & Princeton University
• 0 0 0 0 0 12:39-18:28	Professor David Lary, University of Texas at Dallas
• • • • • • • • • • • • • • • • • • • •	Anthony O'Brien, Princeton University
•□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□	Aircraft teams meeting
•	Ground teams meeting

# <u>Barnett Coordinated Campaign Video Timeline—Day Two</u> (Password = Methane).

•□□□□□□□ 0:00-2:40	Vehicle-based measurements, Picarro & Duke University
•□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□□	Rob Jackson, Duke University
• • • • • • • • • • • • • • • • • • • •	Aircraft teams at airport, Sander Geophysics, NOAA/CU, & Purdue University
• • • • • • • • • • • • • • • • • • • •	Bob Harriss, EDF
• • • • • • • • • • • • • • • • • • • •	Anna Karion, NOAA/CU

David Lyon

Research Analyst

**Environmental Defense Fund** 301 Congress Avenue, Suite 1300

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Austin, TX 78701 (512) 691-3414 <u>dlyon@edf.org</u>

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To: David Lyon[dlyon@edf.org]

Cc: amy.townsend-small@uc.edu[amy.townsend-small@uc.edu];

anna.karion@noaa.gov[anna.karion@noaa.gov]; Anthony O'Brien[anthonyo@princeton.edu]; Bill Hirst[bill.hirst@shell.com]; Birnur Guven[bguven@harc.edu]; Brian Lamb[blamb@wsu.edu]; Brian

Nathan[brian.nathan@utdallas.edu]; Charles Boller[cboller@craworld.com]; Chris

Rella[rella@picarro.com]; Clark, Nigel[Nigel.Clark@mail.wvu.edu]; Colm

Sweeney[colm.sweeney@noaa.gov]; Darrell Anderson[anddarrell@gmail.com]; Dave

Schaefer[captdaveschaefer@gmail.com]; David Steele[dsteele@picarro.com];

david.lary@utdallas.edu[david.lary@utdallas.edu]; Derek Johnson[Derek.Johnson@mail.wvu.edu]; Don

Blake[drblake@uci.edu]; Drew Nelson[dnelson@edf.org]; Thoma, Eben[Thoma.Eben@epa.gov];

ecrosson@picarro.com[ecrosson@picarro.com]; Eric Kort[eakort@umich.edu]; Gabrielle Petron - NOAA

Affiliate[gabrielle.petron@noaa.gov]; Brantley, Halley[Brantley.Halley@epa.gov]; Isobel

Simpson[isimpson@uci.edu]; Josette Marrero[jmarrero@uci.edu]; Kelsey Monk[kmonk@edf.org]; Ken

Davis[kjd10@psu.edu]; lanxin.lindsay@gmail.com[lanxin.lindsay@gmail.com]; Malcolm

Argyle[argyle@sgl.com]; mcambali@purdue.edu[mcambali@purdue.edu]; McKain,

David[David.McKain@mail.wvu.edu]; Morgan Gallagher[morgan.gallagher@duke.edu];

mzondlo@princeton.edu[mzondlo@princeton.edu]; Ramon Alvarez[RAlvarez@edf.org]; Rob

Bennett[robert.bennett@atmosenergy.com]; Robert Harriss[rharriss@edf.org]; Sol

Meyer[sgltexas@sgl.com]; Steve Conley[sconley@scientificaviation.com]; Steve

Edburg[sedburg@wsu.edu]; Steven Hamburg[shamburg@edf.org]; Talbot,

Robert[rtalbot@central.uh.edu]; Tegan Lavoie[tlavoie@purdue.edu]; Thomas

Lauvaux[thomas.lauvaux@carbonnowcast.com]; Tom Ferrara[tferrara@craworld.com]; Touche

Howard[touche\_howard@earthlink.net]

Tracy Tsai From:

Fri 2/21/2014 1:33:29 AM Sent:

Subject: Re: Barnett sites for aerial IR leak survey

Top leakers for EDF helicopter.xlsx

## Hi David,

Attached is a list of the Top 10 Highest Leakers as found by the Plume Scanner. I threw in an additional leak that isn't in the Top 10, but there's also a canister measurement of that site so just in case the helicopter has time, it'd be interesting to have three different measurements of the same site.

Tracy

On Wed, Feb 19, 2014 at 8:49 AM, David Lyon <a href="mailto:sqlyon@edf.org">dlyon@edf.org</a> wrote:

EDF is undertaking a pilot project to measure the frequency of large leaks by helicopter IR survey. As part of the project, the contractor will survey a list of O&G sites in the Barnett Shale. We would like many of these sites to be places of interest for the Barnett Campaign, especially sites where large emissions were detected.

Please send me a list of up to 10 sites of interest with latitude/longitude and a brief description. It would be appreciated if you can get me the information by Friday.

Thanks,

David

estation of the same

David Lyon

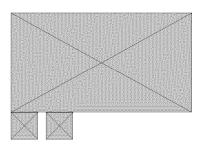
Research Analyst

**Environmental Defense Fund** 301 Congress Avenue, Suite 1300

Austin, TX 78701 (512) 691-3414 dlyon@edf.org

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Tracy Tsai System Engineer



3105 Patrick Henry Drive Santa Clara, CA 95054 Phone: +1 408.962.3957 www.picarro.com

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# <u>List of Project and Researchers Involved in EDF's Efforts To Measure Methane</u> <u>Leakage Across the Natural Gas Industry</u>

PROJECT		RESEARCHERS and SCIENTIFIC ADVISORY PANEL MEMBERS			
Produ	ction				
1. UT Phase 1		David Allen, University of Texas			
		Vincent Torres, University of Texas			
		David Sullivan, University of Texas			
		Matthew Harrison, URS			
		Al Hendler, URS			
		Scott Herndon, Aerodyne			
		Charles Kolb, Aerodyne			
		External Science Advisory Panel to the Study			
		Matthew Fraser, Arizona State University			
		Daniel Hill, Texas A&M University			
		Brian Lamb, Washington State University			
		Jennifer Miskimins, Colorado School of Mines			
		Robert F. Sawyer, University of California, Berkeley			
		John H. Seinfeld, California Institute of Technology			
2.	UT Phase 2	Same as above			
3.	CU Boulder/NOAA	Gabrielle Pétron, University of Colorado, Boulder (CU Boulder) and National Oceanic			
	DJ flights	Atmospheric Administration, Earth System Research Laboratory (NOAA)			
		Anna Karion, CU Boulder and NOAA			
		Colm Sweeney, CU Boulder and NOAA			
		Pieter Tans, NOAA			
4.	CU Boulder/NOAA	Same as above			
5.	Barnett flights HARC/EPA analysis	Birnur Guven, Houston Advanced Research Center			
J.	HARC/LFA allalysis	Eben Thoma, EPA			
		• Epen moma, EPA			
Local					
6.	Multi-city	Brian Lamb, Washington State University			
		Tom Ferrara, Conestoga Rovers and Associates			
		Touche Howard, Conestoga Rovers and Associates			
		Steve Edburg, Washington State University			
		External Science Advisory Panel to the Study			

		Diane Pataki, UC Irvine
		Amy Townsend-Small, University of Cincinnati
		James Whetstone, NIST
		Chuck Kolb, Aerodyne
		Matt Harrison, URS
7.	Boston Phase 2	Steve Wofsy, Harvard
		Rob Jackson, Duke
		Nathan Phillips, Boston University
		Adrian Down, Duke
		Lucy Hutyra, BU
		Kathryn McKain, Harvard
8.	Indianapolis	James Whetstone, NIST
		Kuldeep Prasad, NIST
		Maria Obiminda Cambaliza, Purdue
		Paul Shepson, Purdue
		Ken Davis, Penn State University
		Brian Lamb, Washington State University
		Tom Ferrara, Conestoga Rovers and Associates
		Touche Howard, Conestoga Rovers and Associates
		Steve Edburg, Washington State University
9.	Mapping	Joe Von Fischer, Colorado State University
10.	Pump to Wheels	Nigel Clark, West Virginia University
		Derek Johnson, West Virginia University
		Scott Wayne, West Virginia University
		David McKain, West Virginia University
		Dan Carder, West Virginia University
		Hailin Li, West Virginia University
		External Science Advisory Panel to the Study
		Dave Allen, University of Texas
		Robert "Bob" Sawyer, UC Berkely
		Brent Bailey, NREL
		David Kittelson, University of Minnesota
		Charles Powars, St. Croix Research
		,

11.	Transmission and	Bryan Willson, Colorado State University			
	Storage	Dan Zimmerle, Colorado State University			
		Allen Robinson, Carnegie Mellon University			
		R Subramanian, Carnegie Mellon University			
		External Science Advisory Panel to the Study			
		Jeff Kuo, Calstate Fullerton			
		David Picard, Clearstone Engineering			
		Mike Whelan, Pipeline Research Council			
		Robert Talbot, UH Department of Earth and Atmospheric Sciences			
12.	Gathering and	Anthony Marchese, Colorado State University			
	Processing	Bryan Willson, Colorado State University			
		Dan Zimmerle, Colorado State University			
		Allen Robinson, Carnegie Mellon University			
		R Subramanian, Carnegie Mellon University			
		External Science Advisory Panel to the Study			
		Jim McCarthy, Innovative Environmental Solutions			
		Michael Levi, Council on Foreign Relations			
		David Allen, UT Austin			
13.	Coordinated	Gabrielle Pétron, CU Boulder and NOAA			
15.	Campaign				
		Colm Sweeney, CU Boulder and NOAA     Paul Shanaan Dundus			
		Paul Shepson, Purdue  Pal Talk at Main and Manager			
		Bob Talbot, University of Houston  Patrick Lair at Main and Houston			
		Patrick Laine, University of Houston     Nigel Clark Mark Virginia Heisensites			
		Nigel Clark, West Virginia University      Devals Johnson, West Virginia University			
		Derek Johnson, West Virginia University      Devid McKein, West Virginia University			
		<ul><li>David McKain, West Virginia University</li><li>Rob Jackson, Duke</li></ul>			
		and public production in			
		<ul> <li>Amy Townsend-Small, University of Cincinnati</li> <li>Isobel Simpson, UC-Irvine</li> </ul>			
		Mark Zondlo, Princeton     David Low, LIT Dallas			
		David Lary, UT-Dallas     Frie Crosson Bisarra			
		Eric Crosson, Picarro     Chris Balla, Picarro			
		Chris Rella, Picarro			

14. Pipes top-down (contracts not yet in place)	Dayle McDermitt, LI-COR  George Burba, LI-COR  Liukang Xu, LI-COR  Ken Davis, CarbonNowCast, LLC
15. Synthesis (contracts not yet in place)	
16. Pilot Projects	
a. Boston Phase 1	<ul> <li>Steve Wofsy, Harvard</li> <li>Rob Jackson, Duke</li> <li>Nathan Phillips, Boston University</li> <li>Kathryn McKain, Harvard</li> </ul>
b. UT Arlington drive around	Melanie Sattler, University of Texas Arlington
c. CU Boulder drive around and sensor development	<ul> <li>Jana Milford, University of Colorado, Boulder</li> <li>Mike Hannigan, University of Colorado, Boulder</li> </ul>

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*******	ATTACHMENT	REMOVED	********
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# Barnett Campaign Workshop

Marriott Denver Airport at Gateway Park

http://www.marriott.com/hotels/travel/dengp-denver-airport-marriott-at-gateway-park/16455 E 40th Cir Aurora, CO 80011

# Thursday, January 23

12:00 p.m.	Boxed lunches available in meeting room
1:00-1:15	EDF opens with a discussion on publication strategy
1:15-3:15	Research team presentations (15 minutes + 5 minutes for questions each)
3:15-3:30	Break
3:30-5:30	Research team presentations - continued
5:30-6:30	Collaborating teams meet to discuss integrative approaches to key questions
6:30	Dinner set up in meeting room
6:45-8:00	Collaborating team meetings - continued

# Friday, January 24

7:00 a.m.	Breakfast set up in meeting room
8:00-9:15	Reports from collaborating teams (15 minutes each)
9:15-9:30	Suggestions for additional collaborating teams
9:30-10:30	Discuss key insights, what is missing, and expected bottom line conclusions
10:30-10:45	Break
10:45-12:30	Collaborating teams meet to outline papers, arrange data sharing, discuss needs for additional face-to-face meetings, etc.
12:30 p.m.	Lunch set up in meeting room
12:45-2:00	Collaborating team meetings - continued
2:00-3:00	Discuss how to effectively share data and efficiently move forward on manuscripts
3:00-4:00	Synthesis logistics

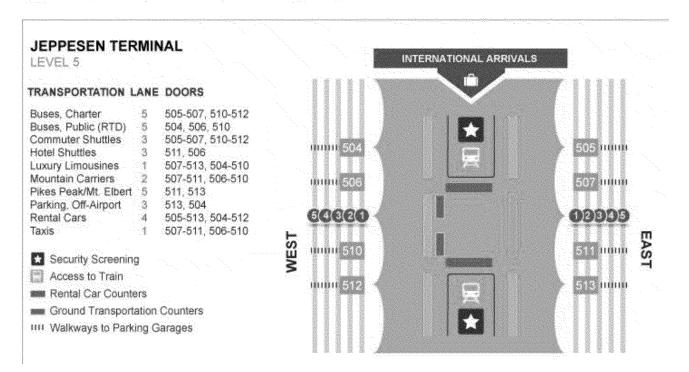
### **Hotel Shuttle Information**

We do have a complimentary airport shuttle that picks up at the airport every 30 min. (on the hour and  $\frac{1}{2}$  hour) from 3:30am to 11:30pm each day. Our hotel shuttle leaves our lobby every 30 min. (on the hour and  $\frac{1}{2}$  hour).

We pick up on the east side terminal first, door 511, and then head over to the west terminal, door 506. They pick up on island three of both sides.

Our large shuttles are white and have the Marriott Gateway Park logo, as well as, Aloft, Marriott Residence Inn, Hilton Garden Inn.

# Jeppesen Terminal, Level 5, Doors 511 & 506



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To: amy.townsend-small@uc.edu[amy.townsend-small@uc.edu]; anna.karion@noaa.gov[anna.karion@noaa.gov]; Anthony O'Brien[anthonyo@princeton.edu]; Bill Hirst[bill.hirst@shell.com]; Birnur Guven[bguven@harc.edu]; Brian Lamb[blamb@wsu.edu]; Brian Nathan [brian.nathan@utdallas.edu]; Charles Boller[cboller@craworld.com]; Chris Rella[rella@picarro.com]; Clark, Nigel[Nigel.Clark@mail.wvu.edu]; Colm Sweeney[colm.sweeney@noaa.gov]; Darrell Anderson[anddarrell@gmail.com]; Dave Schaefer[captdaveschaefer@gmail.com]; David Steele[dsteele@picarro.com]; david.lary@utdallas.edu[david.lary@utdallas.edu]; 'Derek Johnson'[Derek.Johnson@mail.wvu.edu]; 'desiree.plata@duke.edu'['desiree.plata@duke.edu']; Don Blake[drblake@uci.edu]; Drew Nelson[dnelson@edf.org]; Thoma, Eben[Thoma.Eben@epa.gov]; ecrosson@picarro.com[ecrosson@picarro.com]; Eric Kort[eakort@umich.edu]; 'Gabrielle Petron - NOAA Affiliate'[gabrielle.petron@noaa.gov]; Brantley, Halley[Brantley.Halley@epa.gov]; Isobel Simpson[isimpson@uci.edu]; 'Jackson@duke.edu'['Jackson@duke.edu']; 'Joe.von\_Fischer@colostate.edu'['Joe.von\_Fischer@colostate.edu']; Josette Marrero[jmarrero@uci.edu]; Kelsey Monk[kmonk@edf.org]; Ken Davis[kjd10@psu.edu]; lanxin.lindsay@gmail.com[lanxin.lindsay@gmail.com]; Malcolm Argyle[argyle@sgl.com]; mcambali@purdue.edu[mcambali@purdue.edu]; McKain, David[David.McKain@mail.wvu.edu]; Morgan Gallagher[morgan.gallagher@duke.edu]; mzondlo@princeton.edu[mzondlo@princeton.edu]; 'plaine@uh.edu'['plaine@uh.edu']; 'pshepson@purdue.edu'['pshepson@purdue.edu']; Ramon Alvarez[RAlvarez@edf.org]; Rob Bennett[robert.bennett@atmosenergy.com]; Robert Harriss[rharriss@edf.org]; Sol Meyer[sgltexas@sgl.com]; Steve Conley[sconley@scientificaviation.com]; Steve Edburg[sedburg@wsu.edu]; Steven Hamburg[shamburg@edf.org]; Talbot, Robert[rtalbot@Central.UH.EDU]; Tegan Lavoie[tlavoie@purdue.edu]; Thomas Lauvaux[thomas.lauvaux@carbonnowcast.com]; Tom Ferrara[tferrara@craworld.com]; Touche Howard[touche\_howard@earthlink.net]; Tracy Tsai[ttsai@picarro.com] David Lyon From:

Sent: Wed 2/19/2014 4:49:05 PM

Subject: Barnett sites for aerial IR leak survey

especially sites where large emissions were detected.

EDF is undertaking a pilot project to measure the frequency of large leaks by helicopter IR survey. As part of the project, the contractor will survey a list of O&G sites in the Barnett Shale. We would like many of these sites to be places of interest for the Barnett Campaign,

Please send me a list of up to 10 sites of interest with latitude/longitude and a brief description. It would be appreciated if you can get me the information by Friday.

Thanks,

David

Military Mil

David Lyon

Research Analyst

Environmental Defense Fund 301 Congress Avenue, Suite 1300

Austin, TX 78701 (512) 691-3414 dlyon@edf.org

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For further information, please contact the EPA Call Center at  $(866)\ 411-4$ EPA (4372). The TDD number is  $(866)\ 489-4900$ .

\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\* ATTACHMENT NOT DELIVERED \*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*

To: McKittrick, Alexis [IMCEAMAILTO-McKittrick+2EAlexis+40epa+2Egov@URS.COM]; Weitz, Melissa[Weitz.Melissa@epa.gov]  Cc: Shires, Terri[terri.shires@aecom.com]; Thoma, Eben[Thoma.Eben@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]  From: Harrison, Matt  Sent: Thur 2/11/2016 8:48:40 PM  Subject: McKittrick, Alexis [IMCEAMAILTO-McKittrick+2EAlexis+40epa+2Egov@URS.COM]; Weitz, Melissa[Weitz.Melissa@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]  Thoma. Eben@epa.gov]  From: Harrison, Matt  Sent: Thur 2/11/2016 8:48:40 PM  Subject: Meeting on Hi-Flo Sampler with Touché Howard
Dear Alexis and Melissa,
I heard the web presentation made by Mr. Touche Howard when he visited EPA last Friday 2/5/16. Mr. Howard invited me to attend. Thank you for allowing me to listen in. I was surprised by the presence of press at the meeting.
If EPA would like a technical response from the UT-EDF authors to his theories and criticisms, I believe the PI and myself would be happy to discuss that with EPA. Alternately, we can send you some written comments, if you prefer.
Bottom line, while Mr. Howard has some good observations, he has not characterized all the facts appropriately.
If you need an official response, we would like to have the slide deck he presented and shared at your web meeting. Alexis, as your note to Terri Shires suggested, I have requested a copy of the slides from Mr. Howard, but have not received any response to that request.
Let me know if you care to discuss this further.
Thank you,
Matt
Matthew Harrison, P.E.
Vice President

Americas - Ups	tream Oil	&	Gas
----------------	-----------	---	-----

matt.harrison@AECOM.com

512-694-0572

# **AECOM**

9400 Amberglen Blvd., Austin, Texas 78729

www.aecom.com

From: McKittrick, Alexis [mailto:McKittrick.Alexis@epa.gov]

Sent: Tuesday, February 09, 2016 2:12 PM

To: Shires, Terri Cc: Harrison, Matt

Subject: RE: meeting on Hi-Flo Sampler with Touché Howard

Terri,

Attendees of this meeting who are not affiliated with the EPA should contact Touche Howard directly for copies of the slides.

Thanks,

Alexis

From: Shires, Terri [mailto:terri.shires@aecom.com]

Sent: Tuesday, February 09, 2016 9:26 AM

To: McKittrick, Alexis < McKittrick.Alexis@epa.gov > Cc: Harrison, Matt < matt.harrison@aecom.com >

Subject: RE: meeting on Hi-Flo Sampler with Touché Howard

Alexis.

Could you please distribute the slides that Touché' presented last week?

Thank you,

#### **Terri Shires**

Senior Engineer and Project Manager, Design and Construction Services, Gulf Coast Region D +1-512-419-5466 M +1-512-497-6482 Terri.Shires@aecom.com

#### **AECOM**

9400 Amberglen Blvd. Austin, Texas 78729, USA T +1-512-454-4797 aecom.com

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From: McKittrick, Alexis [mailto:McKittrick.Alexis@epa.gov]

Sent: Friday, February 05, 2016 12:56 PM

To: <a href="mailto:ralvarez@edf.org">ralvarez@edf.org</a>; <a href="mailto:lisa.song@insideclimatenews.org">lisa.song@insideclimatenews.org</a>; <a href="mailto:nancy@ncwarn.org">nancy@ncwarn.org</a>; Shires, Terri

Subject: Fwd: meeting on Hi-Flo Sampler with Touche Howard

Sent from my iPhone

https://epawebconferencing.acms.com/r2fk2tdpn9x/

From: Weitz, Melissa

Sent: Wednesday, December 23, 2015 4:35 PM

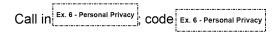
To: Weitz, Melissa; DeFigueiredo, Mark; Waltzer, Suzanne; McKittrick, Alexis;

Macpherson, Alex; Moore, Bruce; Thoma, Eben; Thompson, Lisa; Hambrick, Amy; Banks,

Julius; Irving, Bill **Cc:** Howard, Jodi

Subject: meeting on Hi-Flo Sampler with Touche Howard

When: Friday, February 5, 2016 1:30 PM-2:30 PM. Where: DCRoomWJCS4228AOAP/DC-OAR-OAP



A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

To: amy.townsend-small@uc.edu[amy.townsend-small@uc.edu]; anna.karion@noaa.gov[anna.karion@noaa.gov]; Anthony O'Brien[anthonyo@princeton.edu]; Bill Hirst[bill.hirst@shell.com]; Birnur Guven[bguven@harc.edu]; Brian Lamb[blamb@wsu.edu]; Brian Nathan [brian.nathan@utdallas.edu]; Charles Boller[cboller@craworld.com]; Chris Rella[rella@picarro.com]; Clark, Nigel[Nigel.Clark@mail.wvu.edu]; Colm Sweeney[colm.sweeney@noaa.gov]; Darrell Anderson[anddarrell@gmail.com]; Dave Schaefer[captdaveschaefer@gmail.com]; David Steele[dsteele@picarro.com]; david.lary@utdallas.edu[david.lary@utdallas.edu]; 'Derek Johnson'[Derek.Johnson@mail.wvu.edu]; 'desiree.plata@duke.edu'['desiree.plata@duke.edu']; Don Blake[drblake@uci.edu]; Drew Nelson[dnelson@edf.org]; Thoma, Eben[Thoma.Eben@epa.gov]; ecrosson@picarro.com[ecrosson@picarro.com]; Eric Kort[eakort@umich.edu]; 'Gabrielle Petron - NOAA Affiliate'[gabrielle.petron@noaa.gov]; Brantley, Halley[Brantley.Halley@epa.gov]; Isobel Simpson[isimpson@uci.edu]; 'Jackson@duke.edu'['Jackson@duke.edu']; 'Joe.von\_Fischer@colostate.edu'['Joe.von\_Fischer@colostate.edu']; Josette Marrero[jmarrero@uci.edu]; Kelsey Monk[kmonk@edf.org]; Ken Davis[kjd10@psu.edu]; lanxin.lindsay@gmail.com[lanxin.lindsay@gmail.com]; Malcolm Argyle[argyle@sgl.com]; mcambali@purdue.edu[mcambali@purdue.edu]; McKain, David[David.McKain@mail.wvu.edu]; Morgan Gallagher[morgan.gallagher@duke.edu]; mzondlo@princeton.edu[mzondlo@princeton.edu]; 'plaine@uh.edu'['plaine@uh.edu']; 'pshepson@purdue.edu'['pshepson@purdue.edu']; Ramon Alvarez[RAlvarez@edf.org]; Rob Bennett[robert.bennett@atmosenergy.com]; Robert Harriss[rharriss@edf.org]; Sol Meyer[sgltexas@sgl.com]; Steve Conley[sconley@scientificaviation.com]; Steve Edburg[sedburg@wsu.edu]; Steven Hamburg[shamburg@edf.org]; Talbot, Robert[rtalbot@Central.UH.EDU]; Tegan Lavoie[tlavoie@purdue.edu]; Thomas Lauvaux[thomas.lauvaux@carbonnowcast.com]; Tom Ferrara[tferrara@craworld.com]; Touche Howard[touche\_howard@earthlink.net]; Tracy Tsai[ttsai@picarro.com] David Lyon

From:

Sent: Wed 2/12/2014 10:19:05 PM Subject: Barnett Campaign March 1 reports

# Greetings,

I hope everyone is having fun and making progress analyzing their Barnett Campaign data. As a friendly reminder, preliminary reports are due March 1, followed by a final reports on May 1 and the synthesis in June.

The March 1 reports can be submitted as either a written report or PowerPoint presentation. We would like the reports to address all the following questions:

- What are your preliminary high-level conclusions?
- What is the status of your data?
- samples analyzed and QA/QC

0	expected date to distribute data to collaborators
0	any concerns related to specific data
o pe	any unresolved confidentiality issues (e.g. identity of sites where a company gave you rmission to sample)
•	What manuscripts do you expect to write from your own data?
•	Which teams are you collaborating with or have an interest in collaborating?
0	What data needs to be shared among teams?
0	What are potential manuscripts that can be written by collaborating teams?
•	How do you think your data can be used in the synthesis?
•	What additional work do you expect to perform for the final report?
fo	have also placed the workshop presentations I had saved on my computer into the DropBox lder. You can upload any additional presentations or reports that you would like to share with e group.
<u>ht</u> t	tps://www.dropbox.com/sh/5xvbwm00y7upbal/YwFBTQttYD
Re	egards,
Da	avid
W. C.	
Da	vid Lyon

o format for reporting/sharing (units, uncertainties, spatial & temporal scale, etc.)

#### Research Analyst

**Environmental Defense Fund** 301 Congress Avenue, Suite 1300

Austin, TX 78701 (512) 691-3414 dlyon@edf.org

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\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\* ATTACHMENT NOT DELIVERED \*\*\*\*\*\*\*\*\*\*\*\*\*\*

This Email message contained an attachment named image001.jpg

which may be a computer program. This attached computer program could contain a computer virus which could cause harm to EPA's computers, network, and data. The attachment has been deleted.

This was done to limit the distribution of computer viruses introduced into the EPA network. EPA is deleting all computer program attachments sent from the Internet into the agency via Email.

If the message sender is known and the attachment was legitimate, you should contact the sender and request that they rename the file name extension and resend the Email with the renamed attachment. After receiving the revised Email, containing the renamed attachment, you can rename the file extension to its correct name.

For further information, please contact the EPA Call Center at  $(866)\ 411-4$ EPA (4372). The TDD number is  $(866)\ 489-4900$ .

\* ATTACHMENT NOT DELIVERED \*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*\*

To: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Waltzer,

Suzanne[Waltzer.Suzanne@epa.gov]; McKittrick, Alexis[McKittrick.Alexis@epa.gov]; Macpherson,

Alex[Macpherson.Alex@epa.gov]; Moore, Bruce[Moore.Bruce@epa.gov]; Thoma, Eben[Thoma.Eben@epa.gov]; Thompson, Lisa[Thompson.Lisa@epa.gov]; Hambrick,

Amy[Hambrick.Amy@epa.gov]; Banks, Julius[Banks.Julius@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]

Cc: Howard, Jodi[Howard.Jodi@epa.gov]

From: Weitz, Melissa

**Sent:** Fri 2/5/2016 6:33:19 PM

Subject: Re: meeting on Hi-Flo Sampler with Touche Howard

https://epawebconferencing

Ex. 6 - Personal Privacy

From: Weitz, Melissa

Sent: Wednesday, December 23, 2015 4:35 PM

To: Weitz, Melissa; DeFigueiredo, Mark; Waltzer, Suzanne; McKittrick, Alexis; Macpherson, Alex; Moore,

Bruce; Thoma, Eben; Thompson, Lisa; Hambrick, Amy; Banks, Julius; Irving, Bill

Cc: Howard, Jodi

Subject: meeting on Hi-Flo Sampler with Touche Howard

When: Friday, February 5, 2016 1:30 PM-2:30 PM. Where: DCRoomWJCS4228AOAP/DC-OAR-OAP

Call in Ex. 6 - Personal Privacy 3; code Ex. 6 - Personal Privacy

A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

To:

Thoma, Eben[Thoma.Eben@epa.gov]; Thompson, Lisa[Thompson.Lisa@epa.gov]; Hambrick, Amy[Hambrick.Amy@epa.gov] McKittrick, Alexis[McKittrick.Alexis@epa.gov] Cc: From: Weitz, Melissa Sent: Fri 2/5/2016 5:46:51 PM Subject: calling into Hi Flo meeting? Hi, I wanted to get a sense of how many folks will be on the line for the Touche call at 1:30. Can you let me know if you're able to participate? Thanks! Melissa Melissa Weitz Climate Change Division U.S. Environmental Protection Agency (202) 343-9897 Weitz.Melissa@epa.gov

Macpherson, Alex[Macpherson.Alex@epa.gov]; Moore, Bruce[Moore.Bruce@epa.gov];

To: Thoma, Eben[Thoma.Eben@epa.gov]; McKittrick, Alexis[McKittrick.Alexis@epa.gov]; Frantz,

Chris[Frantz.Chris@epa.gov] **From:** Fernandez, Roger

**Sent:** Wed 10/1/2014 8:15:14 PM

Subject: FW: Revised Powerpoint for today's call

Bacharach Hi Flow Sensor Transition Failure Issues 10 01 2014.pptx

Third time the charm?

Natural Gas STAR Program / Global Methane Initiative Climate Change Division

+1-202-343-9386 epa.gov/gasstar

#### Visiting and Private Mail Carrier Address (FedEx/UPS/DHL)

1201 Constitution Ave NW, Room Number 4351

Washington, DC 20004

USA

#### **Postal Address:**

1200 Pennsylvania Ave., NW (6207M) Washington DC 20460 USA

Hello Everyone!

Attached is the presentation for our 4 PM meeting.

Natural Gas STAR Program / Global Methane Initiative Climate Change Division

+1-202-343-9386 epa.gov/gasstar

#### Visiting and Private Mail Carrier Address (FedEx/UPS/DHL)

1201 Constitution Ave NW, Room Number 4351

Washington, DC 20004

**USA** 

#### **Postal Address:**

1200 Pennsylvania Ave., NW (6207M) Washington DC 20460 USA

From: Touche Howard [mailto:touche howard@earthlink.net]

Sent: Wednesday, October 01, 2014 3:22 PM

**To:** Fernandez, Roger **Cc:** Tom Ferrara

Subject: Revised Powerpoint for today's call

Roger --

Attached is a revised Power Point for today's call. Please distribute as you see fit.

I hope I finally got the day and time right.

Thanks,

Touche'

l and Thomas Ferrara, Conestoga Rovers & Associates

# Backgrou

natural gas facilities Developed in 1993 by Indaco to measure leak rates at

GRI, PRCI, and private companies Extensive measurements were made using the Indaco non-commercial version from 1993 to 2002 for EPA,

Bacharach developed the commercial version of the Hi-Flow Sampler in 2002

Indaco was not involved in that development

# Backgrou

- commercial) version of the sampler emissions measurements using the Indaco (non-Conestoga Rovers has done extensive high flow
- >500 pneumatic devices (private client
- Above and below ground leakage from 13 local distribution companies
- Abandoned well emissions (EDF)
- calibration of the Bacharach Sampler Client came to CRA with questions about the response factor and
- verify its behavior Because CRA uses the Indaco sampler, not the Bacharach Sampler, we conducted field tests of the Bacharach sampler to

# **Sacharaci**

Both the Indaco and Bacharach sampler use the same principle

source) of air (up to 10 scfm) to capture the leak (or other Measures natural gas emissions using a high flow rate

and the net sample concentration after the background concentration is subtracted Calculates emission rate from total sample flow rate

Q = Sample Flow (scfm) x (Sample Conc. - Background Conc. (% gas))

# Bacharaci

- concentration depending on size of leak Two different sensors used to measure sample
- Catalytic Oxidation: Approximately 0% to 5% gas
- Thermal Conductivity: Approximately 5% to 100% gas

these different concentration levels is critical to recognizing the sensor transition problem inderstanding that there are two sensors for

sampler of gas from well heads with 66% methane and 77% methane (balance was heavier hydrocarbons) into the Testing was conducted by releasing known flow rates

of 99.92% methane into the sampler Lab testing was also done by releasing known amounts

## Bacharach Field Testing (Contid.)

Sensor Bacharach sensors was compared to an independent The sample concentration measured by internal

Samplers were similar Response factors of the Indaco and Bacharach

streams, the Bacharach Sampler did not transition as it higher thermal conductivity scale should from the lower catalytic oxidation scale to the However, for most tests with the well head gas

sensor transition in the Bacharach sampler Lab testing using 99.92% methane showed successful

## Contid. D Z

to 100% might indicate 2 to 5% for concentrations ranging >5% Critical problem: Bacharach sample concentrations

measurements of orders of magnitude Possible errors in flux and concentration

At the time, we thought the implications were probably limited to lower methane/heavier hydrocarbon streams

## Allen et al. (2013)

EDF published in September of 2013 University of Texas production study sponsored by

Allen et al. (2013) provides a unique Hi-Flow data set

Variety of source types

Wide range of natural gas concentrations

## \lien et al. (2013)

Our initial interest was in their pneumatic results

those site methane concentration Allen et al. didn't analyze emission rate as a function of Although site methane concentrations were available,

were at sites with higher methane concentrations All the high emitting intermittent pneumatic devices

correlation with concentration This occurs at a threshold, rather than a gradual

## Allen et al. (2013)

flow rate of 6 to 10 scfm emission rates as a function of site methane concentration not available, so we have assumed an average sampler The raw Hi-Flow data (showing sample concentrations) are This prompted us to analyze the entire data set to look at

would generate 5% sample concentrations, the threshold At those sample flows, emission sources of 0.3 – 0.5 scfm thermal conductivity sensor for transition from the catalytic oxidation sensor to the

is shown as a yellow line in the next slide That threshold of transition (0.3 to 0.5 scfm emission rates)

# len et al. (2013) Data Pattern

0.4 scfm at sites with <91% methane concentration Failure - very few sources show emission rates > Data pattern consistent with Sensor Transition

For all source categories:

Sites with wellhead gas methane concentrations >91% had 68 out of 510 measurements (13.3%) >0.4 scfm

Sites with wellhead gas methane concentrations <91% had 4 out of 259 measurements (1.5%) >0.4 scfm

This means that at sites with > 91% methane, the sampler transitioned into the thermal conductivity range over eight times the rate that it did at sites with <91% methane

# (2013) Data Patterr

- methane concentrations in well head gas higher emitters to occur only at sites with high No known phenomenon that would cause
- Pattern occurs across all source categories pneumatic devices, chemical injection pumps, and fanks) (equipment leaks, intermittent and low bleed
- These sources have complete different emission mechanisms

# et al. (2013) Data Pattern

- concentration does failure occur? At what threshold of site methane
- \* Unfortunately, we don't know
- High emitters start showing up at different site methane concentrations for different devices
- Pneumatics: > 94% methane
- Tanks: > 95% methane
- Equipment Leaks > 97% methane
- Might vary with sensor age or other factors
- Some failure might still be occurring even at sites with high methane concentrations

## llen et al. (2013)

analysis showing sensor transition failure in the Response from Dave Allen regarding the Allen et al. (2013) data set:

"There are many factors that can cause changes in equipment in use, the production rates at the site, and others. Attributing the variation in frequencies of frequencies of high emitting controllers (and other done with all factors in mind." which the sampling was done, the maintenance devices), including local regulations in the regions in high emitting devices to particular causes must be practices of the companies owning the controllers (and other devices), ages of equipment, the

# Modrak et al. (2012)

sensor during measurements at production sites Flow exhaust to compare to Hi-Flow internal sample Modrak et al. (2012) collected canister samples from Hi-

Hi-Flow sample sensor was as much as two orders of magnitude too low

accounted for by response factor but the discrepancy is much larger than could be Modrak et al. attributed this to response factor issues

to read concentrations >5%, so the discrepancy is most As seen in next slide, the sample sensor was not able likely due to sensor transition failure

transition failure, although the rate of occurrence was natural gas reading of the Hi-Flow sample sensor this comparison is for methane in the exhaust to the total Ft. Worth Natural Gas Air Quality Study (2011) also relatively low in the Ft. Worth data collected canister samples from Hi-Flow exhaust Canister results were reported with CH<sub>4</sub> but not total HC, so Graph in next slide shows several occurrences of sensor

the sampler worked well most of the time 96%); this high concentration of CH<sub>4</sub> probably explains why Average CH<sub>4</sub> concentration in this region 94.2% (median =

# Follow-up Bacharach Field Testing

Conducted with University of Texas and URS

of 91%, 81%, and 77% same day calibration showed no signs of sensor transition failure at sites with methane concentrations Two Bacharach Samplers with updated firmware and

showed sensor transition failure at site with methane two week old calibration (but passed a response test) concentration = 91% UT Bacharach sampler with updated firmware but a

sites with methane concentrations of 91%, 81%, and After calibration, UT sampler had no further problems

Ŋ

## Imware ssues

Samplers used by Modrak et al. (2012), Ft sensor transition failure occurred routinely had Samplers used for our initial field tests where older firmware

and Allen et al. (2013) also had older firmware Worth Natural Gas Air Quality Study (2011)

#### sites, but technicians felt that this problem had technicians at both transmission and production indicated that samplers could behave erratically Interviews with various industry technicians This erratic behavior was observed by industry This erratic behavior was consistent with sensor An experienced technician would make a measurement would always give a higher measurement be used to re-measure it. The more reliable sampler that seemed too low, so a more reliable sampler would ITMWare Issues

transition failure

been fixed by updating the firmware

### Summary

transition failures old firmware can have wide spread sensor Field testing has established that samplers with

Samplers with newer firmware may also have problems if not calibrated the day of response test. measurement, even if they pass a sensor

firmware show sensor transition failure in their data sets Three studies using samplers with older

## mplications

may have been affected Past measurements - including Subpart W

faulty that are not updated and calibrated may be Current measurements made using samplers

of magnitude Emission rates can be underreported by orders

Super Emitters which drive total emission rates may be underreported

Creates critical safety and environmental

## Suggested Actions

- Sampler reliability Issue guidelines for improved Bacharach Hi-Flow
- Update firmware
- Daily calibrations

after firmware updates and properly calibration

Conduct further testing to verify sampler reliability

## -urther Work

- significant 2013; Subpart W) unknown but possibly very Magnitude of impact on past data sets (Allen et al.
- Might be able to understand better by further testing on samplers with older firmware:
- Understand the thresholds of site methane past concentrations where failure could have occurred in the
- Determine if sensor transition failure could still have and now often occurred even above those site methane thresholds

**To:** Thoma, Eben[Thoma.Eben@epa.gov]; Macpherson, Alex[Macpherson.Alex@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; McKittrick, Alexis[McKittrick.Alexis@epa.gov]

From: Weitz, Melissa

**Sent:** Tue 8/4/2015 4:04:00 PM

Subject: FW: Paper questions Hi Flow Sampler performance

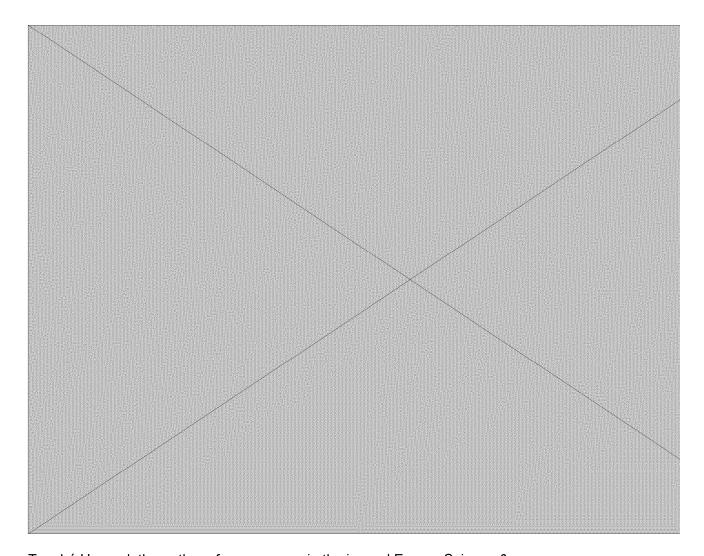
Howard-2015-Energy Science & Engineering.pdf

Let's discuss this paper at our next CH4 monthly check-in.

#### Methane Leaks May Greatly Exceed Estimates, Report Says

By JOHN SCHWARTZAUG. 4, 2015

Photo



Touché Howard, the author of a new paper in the journal Energy Science & Engineering, suggests that the amount of escaped methane could be far greater than accepted estimates. Credit Alex Boerner for The New York Times

A device commonly used to measure the methane that leaks from industrial sources may greatly underestimate those emissions, said an inventor of the technology that the device relies on.

The claim, published Tuesday in a peer-reviewed scientific journal, suggests that the amount of escaped methane, a potent greenhouse gas, could be far greater than accepted estimates from scientists, industry and regulators.

<u>The new paper</u> focuses on a <u>much-heralded report</u> sponsored by the <u>Environmental Defense Fund</u> and published by University of Texas researchers in 2013; that report is part of a major effort to accurately measure the methane problem. But if the supposed

ED\_001785C\_00002148-00002

flaws are borne out, the finding could also have implications for all segments of the <u>natural gas</u> supply chain, with ripple effects on predictions of the rate of <u>climate change</u>, and for efforts and policies meant to combat it.

Almost all of the methane leakage calculated from the Texas research "could be affected by this measurement failure," according to the paper; "their study appears to have systematically underestimated emissions."

The new paper describes a pattern of low measurements of leaks by the <u>Bacharach Hi</u> <u>Flow Sampler</u>, a device approved by the <u>Environmental Protection Agency</u> for its required monitoring of natural gas facilities and in use around the world.

The problem, according to the author of the paper, Touché Howard, is that the backpacksize tool uses two sensors: one for low levels of methane emissions and one for higher levels. As methane levels rise beyond the capacity of the first sensor, the device hands off to the second, high-level sensor.

Mr. Howard found that under some conditions, unless the sampler is carefully and frequently recalibrated, the switchover from the first sampler to the second can fail. When that occurs, the device does not measure the amount of methane that the second sensor would capture, and so it underrecords methane leakage rates.

Mr. Howard, a semiretired gas industry consultant and firefighter who lives in North Carolina, holds the patent for a high-flow-rate sampler whose technology is used in the Bacharach product.

Complicating the issue, he wrote, is that when the device malfunctions, "there is no way to determine the magnitude" of the error without independent measurement at the time, so the missed emissions could be extremely high — perhaps tenfold to a hundredfold for a particularly large leak, he said. Researchers have found that a relatively small number of leaks produce most escaped methane, he wrote, so an instrument that underreports large leaks might skew official assessments like the E.P.A.'s overall methane inventory. Mistakenly low leak readings could also create safety issues in industrial settings, he noted.

"That such an obvious problem could escape notice in this high-profile, landmark study highlights the need for increased vigilance in all aspects of quality assurance" for all methane measurement programs, he wrote.

The paper appears in the journal Energy Science & Engineering.

<u>The Texas study</u>, the first of 16 reports on methane emissions sponsored by the Environmental Defense Fund, measured emissions at 190 natural gas production sites.

The lead author of the Texas study, Prof. David T. Allen, stood by his work. "There may be issues with some of these instruments, but we tested our instruments pretty

thoroughly and when we went out into the field we had multiple instruments, all of which gave us information," he said. Alternate measurement methods were used at some sites, he said, and "we didn't see any evidence that we were missing any large numbers."

The maker of the instrument, Bacharach, reviewed Mr. Howard's new paper, along with one he co-wrote earlier this year. It issued a statement that the sampler, first produced in 2003, was initially tested and validated with gas streams that are not the same as those in the study, which involved high levels of the class of chemicals known as volatile organic compounds.

Even so, the company stated, "we believe that some of the primary test results and conclusion" of the studies "are not valid" because the sensor failures reported by Mr. Howard could be caused by other factors. The company suggested frequent recalibration of the device, and said it would update operating manuals; it also recommended further testing.

A spokeswoman for the E.P.A. said the agency would assess information "from a number of channels," including the research community and industry and the new Howard paper, "as a part of our routine review of new information" for its annual inventory of greenhouse gases.

Methane is the main component of natural gas, and the expansion of techniques such as hydraulic fracturing, known as fracking, has greatly increased the amount of natural gas being extracted, sold and transported around the country. This shift has been widely hailed as environmentally helpful, to the extent that more reliance on natural gas to generate electricity means less reliance on coal and thus smaller amounts of carbon dioxide and other pollutants being pumped into the atmosphere.

Even so, burning natural gas produces some carbon dioxide, and the process of extracting and transporting it inevitably leads to some leakage. Methane has powerful short-term effects on climate change — by some estimates, 80 times the heating effects of carbon dioxide in the first 20 years in the atmosphere — though it breaks down far more quickly than carbon dioxide does.

The Obama administration has lauded the expansion of natural gas as an alternative to coal, but has also called for industry action to sharply reduce leaks while promoting renewable energy sources like solar and wind power.

An expert on methane, Robert Howarth of Cornell University, said he found Mr. Howard's paper "very compelling." Professor Howarth was not involved in the research but has long argued that official estimates of methane emissions are far too low.

Mr. Howard said that before he wrote his paper for the scientific journal, he shared his findings about the sampler with the Environmental Defense Fund and Professor Allen. He said he felt that his concerns were given short shrift, and that early agreements to work together on addressing the issue were brushed aside. "In my opinion, there's been

some real stonewalling going on," he said.

Professor Allen said in response that "our research team made efforts to cooperate with Mr. Howard," adding that he was reluctant to discuss "issues like nondisclosure agreements, email communications, and other university legal matters." A spokesman for the university, Geoffrey Leavenworth, said that communications with Mr. Howard ceased after disagreements over a standard nondisclosure form.

An official of the Environmental Defense Fund said the organization welcomed the new paper. "We're happy when people read these papers, critique them, raise questions about the instruments used, the methodology used," said Mark Brownstein, who leads the group's work on methane emissions.

Other papers in the group's methane series, including a recent <u>study about leaks in the Barnett shale field in Texas</u>, have found far greater emissions of methane than estimated by the E.P.A., he noted, and the studies should be seen as a whole.

The important point, Mr. Brownstein said, is that research shows that relatively inexpensive measures can sharply reduce emissions, however high they turn out to be. "The bottom line is the question is, 'Are emissions high, or are they higher?' Either way, the focus needs to be on reducing them. That's where we come in."

### Correction: August 4, 2015

An earlier version of a headline with this article misidentified the measurement challenged by a new report in the journal Energy Science & Engineering. It is methane leaks, not methane in the atmosphere.

Scott C. Bartos

U.S. Environmental Protection Agency

Climate Change Division

### Visitors and Private Mail Carrier Address (FedEx/UPS/DHL)

1201 Constitution Ave NW, Office 4353 PP

Washington, DC 20004

### USA

### **Postal Address:**

1200 Pennsylvania Ave., NW (6207M) Washington DC 20460 USA

Tel. +1 202 343 9167

Cell +1 202 412 3222

www.globalmethane.org

www.epa.gov/climatechange





ED\_001785C\_00002148-00006

**To:** Thoma, Eben[Thoma.Eben@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Touché Howard[touche\_howard@earthlink.net]; Johnson, Steffan[johnson.steffan@epa.gov]; Ferrara, Thomas[tferrara@craworld.com]

From: Fernandez, Roger

**Sent:** Wed 10/1/2014 8:03:53 PM

Subject: FW: Revised Powerpoint for today's call

Bacharach Hi Flow Sensor Transition Failure Issues 10 01 2014.pptx

Hello Everyone!

Attached is the presentation for our 4 PM meeting.

Natural Gas STAR Program / Global Methane Initiative Climate Change Division

+1-202-343-9386 epa.gov/gasstar

### Visiting and Private Mail Carrier Address (FedEx/UPS/DHL)

1201 Constitution Ave NW, Room Number 4351

Washington, DC 20004

**USA** 

### Postal Address:

1200 Pennsylvania Ave., NW (6207M) Washington DC 20460 USA

From: Touche Howard [mailto:touche\_howard@earthlink.net]

Sent: Wednesday, October 01, 2014 3:22 PM

**To:** Fernandez, Roger **Cc:** Tom Ferrara

Subject: Revised Powerpoint for today's call

Roo	er	

Attached is a revised Power Point for today's call. Please distribute as you see fit.

I hope I finally got the day and time right.

Thanks,

Touche'

To: Thoma, Eben[Thoma.Eben@epa.gov]; DeFigueiredo,

Mark[DeFigueiredo.Mark@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Touché Howard[touche howard@earthlink.net]; Johnson, Steffan[johnson.steffan@epa.gov]; Ferrara,

Thomas[tferrara@craworld.com]

:: Frantz, Chris[Frantz.Chris@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov];

McKittrick, Alexis[McKittrick.Alexis@epa.gov]

From: Fernandez, Roger

**Sent:** Tue 9/30/2014 9:18:18 PM

Subject: RE: Hi-Flow Sampler Issues - How it relates to Subpart W and Possibly Quad O

Hi Everyone,

Something very odd is going on for now two people said this meeting was on their calendar for today at 4. It is actually tomorrow (Wednesday) Oct 1 at 4 PM.

Hope everyone can make it.

Thanks!!!

Natural Gas STAR Program / Global Methane Initiative Climate Change Division

+1-202-343-9386 epa.gov/gasstar

### Visiting and Private Mail Carrier Address (FedEx/UPS/DHL)

1201 Constitution Ave NW, Room Number 4351 Washington, DC 20004 USA

### **Postal Address:**

1200 Pennsylvania Ave., NW (6207M) Washington DC 20460 USA

----Original Appointment-----

From: Fernandez, Roger

Sent: Friday, September 19, 2014 10:51 AM

To: Fernandez, Roger; Thoma, Eben; DeFigueiredo, Mark; Weitz, Melissa; Touché Howard;

Johnson, Steffan; Ferrara, Thomas

Cc: Frantz, Chris; Waltzer, Suzanne; McKittrick, Alexis

**Subject:** Hi-Flow Sampler Issues - How it relates to Subpart W and Possibly Quad O **When:** Thursday, October 02, 2014 11:30 AM-12:00 PM (UTC-05:00) Eastern Time (US &

Canada).

Where: By phone - see call in number

Hello Everyone,

This meeting request is a follow up to a call I had with Mr. Touche Howard and Mr. Thomas Ferrara regarding their experience with the Hi-flow sampler and some potential measurement issues associated with it.

As they noted, their primary concern is that this may result in important safety, measurement and environmental issues. They believe that this could be solved by users updating their firmware and conducting daily calibrations (as opposed to just bump tests).

I am not sure if / what authority we have in this regard but as this potential measurement error problem could impact our inventory numbers and Quad O applicability assessments, I suggest we have this discussion.

Please use the following call in number:

Dial: Conf Code:

Ex. 6 - Personal Privacy

THANKS!!

To: Thoma, Eben[Thoma.Eben@epa.gov]; DeFigueiredo,

Mark[DeFigueiredo.Mark@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Touché Howard[touche\_howard@earthlink.net]; Johnson, Steffan[johnson.steffan@epa.gov]; Ferrara, Thomas[tferrara@craworld.com]

Cc: Frantz, Chris[Frantz.Chris@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]

From: Fernandez, Roger Sent: Fri 9/26/2014 5:24:03 PM

Subject: RE: Hi-Flow Sampler Issues - How it relates to Subpart W and Possibly Quad O

Hello Everyone,

I'm sorry about needing to move this meeting time. Not sure exactly what the meeting is about but Paul Gunning sent me an invite for the exact time and it isn't a career enhancing move to decline your boss' boss if you are physically in the city that day.

Hope everyone can make this new time.

Roger

Natural Gas STAR Program / Global Methane Initiative Climate Change Division

+1-202-343-9386 epa.gov/gasstar

### Visiting and Private Mail Carrier Address (FedEx/UPS/DHL)

1201 Constitution Ave NW, Room Number 4351 Washington, DC 20004 USA

### **Postal Address:**

1200 Pennsylvania Ave., NW (6207M) Washington DC 20460 USA

-----Original Appointment-----From: Fernandez, Roger

Sent: Friday, September 19, 2014 10:51 AM

To: Fernandez, Roger; Thoma, Eben; DeFigueiredo, Mark; Weitz, Melissa; Touché Howard;

Johnson, Steffan; Ferrara, Thomas **Cc:** Frantz, Chris; Waltzer, Suzanne

**Subject:** Hi-Flow Sampler Issues - How it relates to Subpart W and Possibly Quad O **When:** Wednesday, October 01, 2014 4:00 PM-4:30 PM (UTC-05:00) Eastern Time (US &

Canada).

Where: By phone - see call in number

Hello Everyone,

This meeting request is a follow up to a call I had with Mr. Touche Howard and Mr. Thomas Ferrara regarding their experience with the Hi-flow sampler and some potential measurement issues associated with it.

As they noted, their primary concern is that this may result in important safety, measurement and environmental issues. They believe that this could be solved by users updating their firmware and conducting daily calibrations (as opposed to just bump tests).

I am not sure if / what authority we have in this regard but as this potential measurement error problem could impact our inventory numbers and Quad O applicability assessments, I suggest we have this discussion.

Please use the following call in number:

Dial: Conf Code:

Ex. 6 - Personal Privacy

THANKS!!

To: Macpherson, Alex[Macpherson.Alex@epa.gov]; Hambrick, Amy[Hambrick.Amy@epa.gov];

Thompson, Lisa[Thompson.Lisa@epa.gov]; Thoma, Eben[Thoma.Eben@epa.gov]; Snyder,

Jennifer[Snyder.Jennifer@epa.gov]

From: Weitz, Melissa

**Sent:** Tue 12/1/2015 6:12:02 PM

Subject: RE: OAR-16-000-1201 - Letter Argues Instrument Incorrectly Measures Methane Emissions

Thank you! I'll include you in the follow up meeting with Howard.

From: Macpherson, Alex

Sent: Monday, November 30, 2015 2:35 PM

**To:** Weitz, Melissa < Weitz. Melissa @epa.gov>; Hambrick, Amy < Hambrick. Amy @epa.gov>; Thompson, Lisa < Thompson. Lisa @epa.gov>; Thoma, Eben @epa.gov>; Snyder,

Jennifer <Snyder.Jennifer@epa.gov>

Subject: RE: OAR-16-000-1201 - Letter Argues Instrument Incorrectly Measures Methane

**Emissions** 

Hi Melissa

I think your letter is fine. I don't have anything to add. It would be good to meet to discuss.

Thanks

Alex

From: Weitz, Melissa

Sent: Monday, November 30, 2015 2:19 PM

**To:** Macpherson, Alex; Hambrick, Amy; Thompson, Lisa; Thoma, Eben; Snyder, Jennifer **Subject:** FW: OAR-16-000-1201 - Letter Argues Instrument Incorrectly Measures Methane

**Emissions** 

Hello,

Janet received a letter from Touche Howard on the Hi Flow sampler issue.

The attached PDF includes Touche's letter (~1 page) and his two articles, which he appended to the letter.

My draft response ( $\sim$ 1 page) is in the attached word document. It basically notes that we are aware of Touche's articles on the hi flow, are currently evaluating a number of data sources for our GHG estimates, and that we are willing to meet with him.

If anyone would like to review and has edits or comments, please send them to me by COB tomorrow. I'm also happy to answer any questions-just let me know.

Thank you!

Melissa

From: Hargrove, Anne

Sent: Thursday, November 12, 2015 12:07 PM

To: Franklin, Pamela < Franklin.Pamela@epa.gov >
Cc: Briscoe, Earline < Briscoe.Earline@epa.gov >

Subject: OAR-16-000-1201 - Letter Argues Instrument Incorrectly Measures Methane

**Emissions** 

OAR-16-000-1201

Hi Pamela:

Attached you will find an incoming letter from Howard Touche to Janet. Touche argues that the Bacharach Hi-Flow Sampler (BHFS) seriously under-reports methane emission leak rates that occur in natural gas production. He also has attached to his letter two papers on this subject.

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If you think your branch is the correct place to respond to this control, please let me know what kind of extension you will need to produce a draft. The response is to be signed by Sarah. If this letter should be handled by a different branch, please let me know right away. I think you may need an extension because the current due date is Nov. 18, which means we would have to get it at the very latest by the end of the day Monday Nov. 16, which seems unreasonable.

If you think the response should involve collaboration with other branches, I can send this email to whomever you designate.

In addition to the incoming correspondence, I have attached the information sheet for this control, in case you need further information about it. Also, I've attached a sample response letter you should use to format your response.

Thank you,

Anne Hargrove

Climate Change Division

U.S. Environmental Protection Agency

(202) 343-9926

**To:** Weitz, Melissa[Weitz.Melissa@epa.gov]; Hambrick, Amy[Hambrick.Amy@epa.gov]; Thompson, Lisa[Thompson.Lisa@epa.gov]; Thoma, Eben[Thoma.Eben@epa.gov]; Snyder, Jennifer[Snyder.Jennifer@epa.gov]

From: Macpherson, Alex

**Sent:** Mon 11/30/2015 7:34:40 PM

Subject: RE: OAR-16-000-1201 - Letter Argues Instrument Incorrectly Measures Methane Emissions

Hi Melissa

I think your letter is fine. I don't have anything to add. It would be good to meet to discuss.

Thanks Alex

From: Weitz, Melissa

Sent: Monday, November 30, 2015 2:19 PM

**To:** Macpherson, Alex; Hambrick, Amy; Thompson, Lisa; Thoma, Eben; Snyder, Jennifer **Subject:** FW: OAR-16-000-1201 - Letter Argues Instrument Incorrectly Measures Methane

**Emissions** 

Hello,

Janet received a letter from Touche Howard on the Hi Flow sampler issue.

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Melissa

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**Sent:** Thursday, November 12, 2015 12:07 PM **To:** Franklin, Pamela < Franklin, Pamela@epa.gov > Cc: Briscoe, Earline < Briscoe, Earline@epa.gov >

Subject: OAR-16-000-1201 - Letter Argues Instrument Incorrectly Measures Methane

Emissions

OAR-16-000-1201

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If you think your branch is the correct place to respond to this control, please let me know what kind of extension you will need to produce a draft. The response is to be signed by Sarah. If this letter should be handled by a different branch, please let me know right away. I think you may need an extension because the current due date is Nov. 18, which means we would have to get it at the very latest by the end of the day Monday Nov. 16, which seems unreasonable.

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Thank you,

Anne Hargrove

Climate Change Division

U.S. Environmental Protection Agency

(202) 343-9926

l and Thomas Ferrara, Conestoga Rovers & Associates

# Backgrou

Developed in 1993 by Indaco to measure leak rates at

natural gas facilities

GRI, PRCI, and private companies Extensive measurements were made using the Indaco non-commercial version from 1993 to 2002 for EPA,

Bacharach developed the commercial version of the Hi-Flow Sampler in 2002

Indaco was not involved in that development

# Backgrou

- commercial) version of the sampler emissions measurements using the Indaco (non-Conestoga Rovers has done extensive high flow
- >500 pneumatic devices (private client
- Above and below ground leakage from 13 local distribution companies
- Abandoned well emissions (EDF)
- calibration of the Bacharach Sampler Client came to CRA with questions about the response factor and
- verify its behavior Because CRA uses the Indaco sampler, not the Bacharach Sampler, we conducted field tests of the Bacharach sampler to

# **Sacharaci**

Both the Indaco and Bacharach sampler use the same principle

source) of air (up to 10 scfm) to capture the leak (or other Measures natural gas emissions using a high flow rate

and the net sample concentration after the background concentration is subtracted Calculates emission rate from total sample flow rate

Q = Sample Flow (scfm) x (Sample Conc. - Background Conc. (% gas))

4

# Bacharaci

- concentration depending on size of leak Two different sensors used to measure sample
- Catalytic Oxidation: Approximately 0% to 5% gas
- Thermal Conductivity: Approximately 5% to 100% gas
- these different concentration levels is critical to recognizing the sensor transition problem inderstanding that there are two sensors for

sampler of gas from well heads with 66% methane and 77% methane (balance was heavier hydrocarbons) into the Testing was conducted by releasing known flow rates

## Bacharach Field Testing (Contid.)

Sensor Bacharach sensors was compared to an independent The sample concentration measured by internal

Samplers were similar Response factors of the Indaco and Bacharach

streams, the Bacharach Sampler did not transition as it higher thermal conductivity scale should from the lower catalytic oxidation scale to the However, for most tests with the well head gas

sensor transition in the Bacharach sampler Lab testing using 99.92% methane showed successful

## Contid. D Z

to 100% might indicate 2 to 5% for concentrations ranging >5% Critical problem: Bacharach sample concentrations

measurements of orders of magnitude Possible errors in flux and concentration

At the time, we thought the implications were probably limited to lower methane/heavier hydrocarbon streams

## llen et al. (2013)

EDF published in September of 2013 University of Texas production study sponsored by

Allen et al. (2013) provides a unique Hi-Flow data set

Variety of source types

Wide range of natural gas concentrations

# Allen et al. (2013)

Our initial interest was in their pneumatic results

those site methane concentration Allen et al. didn't analyze emission rate as a function of Although site methane concentrations were available,

were at sites with higher methane concentrations All the high emitting intermittent pneumatic devices

correlation with concentration This occurs at a threshold, rather than a gradual

# \lien et al. (2013)

emission rates as a function of site methane concentration flow rate of 6 to 10 scfm not available, so we have assumed an average sampler The raw Hi-Flow data (showing sample concentrations) are This prompted us to analyze the entire data set to look at

would generate 5% sample concentrations, the threshold At those sample flows, emission sources of 0.3 – 0.5 scfm thermal conductivity sensor for transition from the catalytic oxidation sensor to the

is shown as a yellow line in the next slide That threshold of transition (0.3 to 0.5 scfm emission rates)

# len et al. (2013) Data Pattern

- 0.4 scfm at sites with <91% methane concentration Failure - very few sources show emission rates > Data pattern consistent with Sensor Transition
- For all source categories:
- Sites with wellhead gas methane concentrations >91% had 68 out of 510 measurements (13.3%) >0.4 scfm
- Sites with wellhead gas methane concentrations <91% had 4 out of 259 measurements (1.5%) >0.4 scfm
- This means that at sites with > 91% methane, the sampler transitioned into the thermal conductivity range over eight times the rate that it did at sites with <91% methane

- methane concentrations in well head gas higher emitters to occur only at sites with high No known phenomenon that would cause
- Pattern occurs across all source categories pneumatic devices, chemical injection pumps, and fanks) (equipment leaks, intermittent and low bleed
- These sources have complete different emission mechanisms

# et al. (2013) Data Pattern

- concentration does failure occur? At what threshold of site methane
- Unfortunately, we don't know
- High emitters start showing up at different site methane concentrations for different devices
- Pneumatics: > 94% methane
- Tanks: > 95% methane
- Equipment Leaks > 97% methane
- Might vary with sensor age or other factors Some failure might still be occurring even at sites

with high methane concentrations

# llen et al. (2013)

- analysis showing sensor transition failure in the Response from Dave Allen regarding the Allen et al. (2013) data set:
- "There are many factors that can cause changes in equipment in use, the production rates at the site, and others. Attributing the variation in frequencies of frequencies of high emitting controllers (and other done with all factors in mind." which the sampling was done, the maintenance devices), including local regulations in the regions in high emitting devices to particular causes must be practices of the companies owning the controllers (and other devices), ages of equipment, the

# Modrak et al. (2012)

sensor during measurements at production sites Flow exhaust to compare to Hi-Flow internal sample Modrak et al. (2012) collected canister samples from Hi-

Hi-Flow sample sensor was as much as two orders of magnitude too low

accounted for by response factor but the discrepancy is much larger than could be Modrak et al. attributed this to response factor issues

to read concentrations >5%, so the discrepancy is most As seen in next slide, the sample sensor was not able likely due to sensor transition failure

transition failure, although the rate of occurrence was natural gas reading of the Hi-Flow sample sensor this comparison is for methane in the exhaust to the total Ft. Worth Natural Gas Air Quality Study (2011) also relatively low in the Ft. Worth data collected canister samples from Hi-Flow exhaust Canister results were reported with CH<sub>4</sub> but not total HC, so Graph in next slide shows several occurrences of sensor

the sampler worked well most of the time

96%); this high concentration of CH<sub>4</sub> probably explains why

Average CH<sub>4</sub> concentration in this region 94.2% (median =

# Follow-up Bacharach Field Testing

Conducted with University of Texas and URS

of 91%, 81%, and 77% same day calibration showed no signs of sensor transition failure at sites with methane concentrations Two Bacharach Samplers with updated firmware and

showed sensor transition failure at site with methane two week old calibration (but passed a response test) concentration = 91% UT Bacharach sampler with updated firmware but a

sites with methane concentrations of 91%, 81%, and After calibration, UT sampler had no further problems

## -irmware Issues

sensor transition failure occurred routinely had Samplers used for our initial field tests where older firmware

and Allen et al. (2013) also had older firmware Samplers used by Modrak et al. (2012), Ft Worth Natural Gas Air Quality Study (2011)

## irmware Issues

transition failure indicated that samplers could behave erratically Interviews with various industry technicians This erratic behavior was consistent with sensor

An experienced technician would make a measurement would always give a higher measurement be used to re-measure it. The more reliable sampler that seemed too low, so a more reliable sampler would

sites, but technicians felt that this problem had technicians at both transmission and production been fixed by updating the firmware This erratic behavior was observed by industry

## Summary

transition failures old firmware can have wide spread sensor Field testing has established that samplers with

Samplers with newer firmware may also have problems if not calibrated the day of response test. measurement, even if they pass a sensor

firmware show sensor transition failure in their data sets Three studies using samplers with older

## mplications

may have been affected Past measurements - including Subpart W

faulty that are not updated and calibrated may be Current measurements made using samplers

of magnitude Emission rates can be underreported by orders

Super Emitters which drive total emission rates may be underreported

Creates critical safety and environmental

## Suggested Actions

- Sampler reliability Issue guidelines for improved Bacharach Hi-Flow
- Update firmware
- Daily calibrations

after firmware updates and properly calibration

Conduct further testing to verify sampler reliability

## -urther Work

- significant 2013; Subpart W) unknown but possibly very Magnitude of impact on past data sets (Allen et al.
- Might be able to understand better by further testing on samplers with older firmware:
- Understand the thresholds of site methane past concentrations where failure could have occurred in the
- Determine if sensor transition failure could still have and now often occurred even above those site methane thresholds

### **Energy Science & Engineering**

Open Access

RESEARCH ARTICLE

### University of Texas study underestimates national methane emissions at natural gas production sites due to instrument sensor failure

Touché Howard

Indaco Air Quality Services, Inc., Durham, North Carolina

### Keywords

Greenhouse gases, methane, natural gas

### Correspondence

Touché Howard, Indaco Air Quality Services, Inc., Durham, NC. Tel: (919) 943-9406; E-mail: touche.howard@indacoaqs.com

### **Funding Information**

This paper used data that are publicly available and did not rely on external funding.

Received: 25 November 2014; Revised: 13 May 2015; Accepted: 23 June 2015

doi: 10.1002/ese3.81

### Abstract

The University of Texas reported on a campaign to measure methane  $(CH_A)$ emissions from United States natural gas (NG) production sites as part of an improved national inventory. Unfortunately, their study appears to have systematically underestimated emissions. They used the Bacharach Hi-Flow® Sampler (BHFS) which in previous studies has been shown to exhibit sensor failures leading to underreporting of NG emissions. The data reported by the University of Texas study suggest their measurements exhibit this sensor failure, as shown by the paucity of high-emitting observations when the wellhead gas composition was less than 91% CH<sub>4</sub>, where sensor failures are most likely; during follow-up testing, the BHFS used in that study indeed exhibited sensor failure consistent with under-reporting of these high emitters. Tracer ratio measurements made by the University of Texas at a subset of sites with low CH4 content further indicate that the BHFS measurements at these sites were too low by factors of three to five. Over 98% of the CH 4 inventory calculated from their own data and 41% of their compiled national inventory may be affected by this measurement failure. Their data also indicate that this sensor failure could occur at NG compositions as high as 97% CH<sub>4</sub>, possibly affecting other BHFS measurement programs throughout the entire NG supply chain, including at transmission sites where the BHFS is used to report greenhouse gas emissions to the United States Environmental Protection Agency Greenhouse Gas Reporting Program (USEPA GHGRP, U.S. 40 CFR Part 98, Subpart W). The presence of such an obvious problem in this high profile, landmark study highlights the need for increased quality assurance in all greenhouse gas measurement programs.

### Introduction

The climatic benefits of switching from coal to natural gas (NG) depend on the magnitude of fugitive emissions of methane ( $\mathrm{CH_4}$ ) from NG production, processing, transmission, and distribution [12, 13, 27]. This is of particular concern as the United States increasingly exploits NG from shale formations: a sudden increase in  $\mathrm{CH_4}$  emissions due to increased NG production could trigger climate "tipping points" due to the high short-term global warming potential of  $\mathrm{CH_4}$  (86× carbon dioxide on a 20-year time scale) [19]. The United States Environmental

Protection Agency (USEPA) estimates  $\mathrm{CH_4}$  emissions from the NG supply chain by scaling up individual ground-level measurements, mostly collected by reporting from industry [26]. However, some recent studies have questioned whether these "bottom-up" inventories are too low, since airborne measurements indicate that  $\mathrm{CH_4}$  emissions from NG production regions are higher than the inventories indicate [5, 14, 17, 20, 21].

In order to help determine the climate consequences of expanded NG production and use, and to address the apparent discrepancy in top-down and bottom-up measurements, the University of Texas (UT) at Austin and the

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ED 001785C 00002149-00001

1

UT Study Underestimates Methane Emissions

Environmental Defense Fund launched a large campaign to measure CH4 emissions at NG production sites in the United States [1]. This study used both existing EPA GHG inventory data and new measurements to compile a new national inventory of CH<sub>4</sub> emissions from production sites. Forty-one percent of this new inventory was based on measurements made by [1], which included measurements of emissions from well completion flowbacks as well as measurements of emissions from chemical injection pumps, pneumatic devices, equipment leaks, and tanks at 150 NG production sites around the United States already in routine operation (measurements from tanks were not used for inventory purposes). However, the measurements of emissions at well production sites already in operation (which comprised 98% of the new inventory developed by [1]) were made using the Bacharach Hi-Flow Sampler (BHFS; Bacharach, Inc., New Kensington, PA) and recent work has shown that the BHFS can underreport individual emissions measurements by two orders of magnitude [10]. This anomaly occurs due to sensor transition failure that can prevent the sampler from properly measuring NG emission rates greater than ~0.4 standard cubic feet per minute (scfm; 1 scfm =  $1.70 \text{ m}^3 \text{ h}^{-1}$  or  $19.2 \text{ g min}^{-1}$  for pure CH<sub>4</sub> at 60°F [15.6°C] and 1 atm; these are the standard temperature and pressure used by the U.S. NG industry). Although this failure is not well understood, it does not seem to occur when measuring pure CH<sub>4</sub> streams, but has been observed in four different samplers when measuring NG streams with CH4 contents ranging from 66% to 95%. The sampler's firmwareversion and elapsed time since last calibration may also influence the occurrence of this problem [10, 18].

This paper presents an analysis of the UT [1] emissions measurements that were made with the BHFS, and shows that high emitters (>0.4 sofm [0.7  $\rm m^3~h^{-1}$ ]) were reported very rarely at sites with a low CH<sub>4</sub> content in the well-head gas (<91%), consistent with sensor transition failure. It also details testing of the exact BHFS instrument used in that study and shows the occurrence of this sensor failure at an NG production site with a wellhead composition of 91% CH<sub>4</sub> (the highest CH<sub>4</sub> concentration site available during testing). Finally, the downwind tracer ratio measurements made by [1] at a subset of their test sites are reexamined and indicate that the BHFS measurements made at sites with low wellhead CH<sub>4</sub> concentrations were too low by factors of three to five.

### **Evidence of BHFS Sensor Transition Failure in the UT Dataset**

The Allen et al. [1] UT dataset is unique due to the large number of BHFS measurements made across a wide geographic range, the variety of emissions sources

(equipment leaks, pneumatic devices, chemical injection pumps, and tanks) and the wide range of NG compositions (67.4–98.4%  $\mathrm{CH_4})$  that were sampled. As such, the UT study provides an important opportunity to evaluate the occurrence of sensor transition failure in the BHFS as well as the impact of this issue on emission rates and emissions factors based on measurements in other segments of the NG supply chain.

The BHFS uses a high flow rate of air and a loose enclosure to completely capture the NG-emitting from a source, with the emission rate calculated from the total flow rate of air and the resulting sample NG concentration, after the background NG concentration is subtracted. The sampler uses a catalytic oxidation sensor to measure sample concentrations from 0% to 5% NG in air, but must transition to a thermal conductivity sensor in order to accurately measure sample concentrations higher than 5%. It is the failure of the sampler to transition to the higher range that has been previously observed by Howard et al. [10] and which can prevent the sampler from correctly measuring emission rates larger than 0.3–0.5 scfm (0.5–0.9 m³ h<sup>-1</sup>) (corresponding to sampler flow rates of 6–10 scfm [10–17 m³ h<sup>-1</sup>]). Figure 1 summarizes data

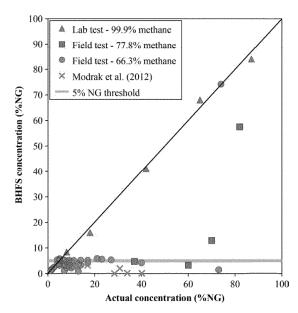


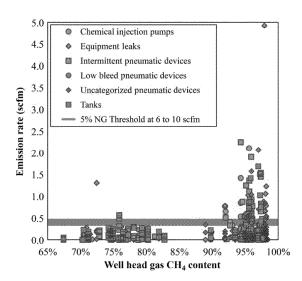
Figure 1. Occurrence of sensor transition failure in BHFS instruments with natural gas of varying CH<sub>4</sub> content from field and lab testing and from emission measurement studies (data from [10, 18]). NG concentrations in the BHFS sampling system measured by the BHFS internal sensor are compared to independent measurements of the sample NG concentrations. The 5% NG sample concentration threshold is the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity. BHFS, Bacharach Hi-Flow Sampler; NG, natural gas.

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showing the occurrence of sensor transition failure in several BHFS instruments during both fieldand laboratory testing as well as an example of the failure that occurred during an emission measurement study [10, 18].

Figure 2 presents the BHFS emission measurements from [1] as a function of percent  $CH_4$  in wellhead gas at each site. Figure 2 also shows a line corresponding to emission rates of 0.3–0.5 scfm (0.5–0.9  $\mathrm{m}^3$   $\mathrm{h}^{-1}$ ), which represents the range of emission rates that would require transition from the catalytic oxidation sensor to the thermal conductivity sensor at sample flows ranging from 6 to 10 scfm (10–17  $\mathrm{m}^3$   $\mathrm{h}^{-1}$ ).

As seen in Figure 2, there are very few measurements in the thermal conductivity sensor range (above  $\sim 0.4$  scfm  $[0.7 \text{ m}^3 \text{ h}^{-1}]$ ) at sites where the wellhead gas composition of CH<sub>4</sub> is less than 91%, and this is true across all source categories. Raw data for sample flowand concentration from the BHFS were not provided in [1] supplemental information, so for this analysis, an average BHFS sample flowrate of 8 scfm (14 m  $^3$  h $^{-1}$ ) has been assumed, which is the lower of the two sampling flows specified by the Bacharach operating manual [4]. At this sample flowrate, an emission source of 0.4 scfm (0.7 m $^3$  h $^{-1}$ ) corresponds with a sample concentration of 5% NG in air, above



**Figure 2.** Emission rates of various sources measured by BHFS at NG production sites versus CH  $_4$  concentration of the wellhead gas (data from [1]). The solid line indicates the maximum emission rate that could be measured by the catalytic oxidation sensor only (i.e., in the case of sensor transition failure). For sites with a NG composition greater than 91% CH $_4$ , 13.3% of the measurements are in the TCD sensor range, assuming a sampler flow rate of 8 cubic feet per minute. For sites with less than 91% CH $_4$ , only 1.5% of the measurements are in the TCD range. BHFS, Bacharach HiFlow Sampler; NG, natural gas; TCD, thermal conductivity detector.

which point the sampler would need to transition to the thermal conductivity sensor to allow for accurate measurements. For sites with CH<sub>4</sub> concentrations less than 91%, only four out of 259 measurements (1.5%) exceeded 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>), while for sites with CH<sub>4</sub> concentrations greater than 91%, 68 out of 510 measurements (13.3%) exceeded 0.4 scfm  $(0.7 \text{ m}^3 \text{ h}^{-1})$ . Consequently, there were almost nine times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH $_4$  (Fig. 2). If the sample flow rate were 6 scfm (10 m $^3$  h $^{-1}$ ) (due to a flow restriction or reduced battery power), the threshold for transition to the thermal conductivity range would be 0.3 scfm (0.5 m<sup>3</sup> h<sup>-1</sup>); this would still mean that there were almost seven times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH<sub>4</sub> than at sites with >91% CH<sub>4</sub>. Although it is well known that a small percentage of NG emission sources account for most of the total emissions from any given population [9, 15, 25], it is unlikely that almost all the significant emitters at NG production sites would occur only at sites with well head gas compositions >91% CH, It is also unlikely that the emission rates of all of the source categories surveyed by [1], which had diverse emission mechanisms such as equipment leaks, pneumatic controllers, chemical injection pumps, and tanks, would all have a ceiling of ~0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) at sites with lower wellhead gas CH₄ concentrations. Consequently, the low occurrence of high emitters at sites with lower wellhead gas CH<sub>4</sub> concentrations in [1] indicates that sensor transition failure occurred at sites with CH<sub>4</sub> content <91% and is consistent with the BHFS sensor failure found by Howard et al. [10].

### Alternative Theories for the Emission Rate Pattern

Other possible causes of the emission rate pattern in the UT BHFS measurements were considered, including: regional operating differences at production sites; lighter gas densities resulting in higher emission rates; and improved detection of emissions by auditory, visual, and olfactory (AVO, e.g., [24]) methods at sites with heavier hydrocarbon concentrations.

### Regional operating differences

Allen et al. [1] point out that air pollution regulations in Colorado which required installation of low bleed pneumatic devices in ozone nonattainment areas after 2009 might have led to lower emission rates in the Rocky Mountain region, which also had the lowest average concentration of  ${\rm CH_4}$  in the wellhead gas. However, if the

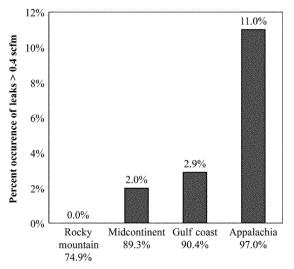
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Rocky Mountain region is removed from the analysis, the occurrence of emitters >0.4 scfm (0.7 m³ h^-1) at sites with wellhead gas <91% CH<sub>4</sub> was still only four out of 129 measurements (3.1%), while for sites with CH<sub>4</sub> concentrations greater than 91%, there remain 68 out of 510 measurements (13.3%) that exceeded 0.4 scfm (0.7 m³ h^-1) (there were no Rocky Mountain sites with CH<sub>4</sub> >91%). Consequently, even if the Rocky Mountain region is removed from consideration, the occurrence of emitters >0.4 scfm (0.7 m³ h^-1) was almost four times less at sites with less than 91% CH<sub>4</sub> than at sites with greater than 91% CH<sub>4</sub>, so air quality regulations in Colorado do not appear to be the cause of the emission rate trend shown in Figure 2.

Beyond air pollution regulations, other unknown regional operating practices unrelated to  ${\rm CH_4}$  concentration might coincidentally cause the apparent relationship of site  ${\rm CH_4}$  concentrations with the occurrence of high emitters. However, as shown in Figure 3, the increase in leaks >0.4 scfm  $(0.7~{\rm m^3~h^{-1}})$  directly correlates with the increase in the average regional  ${\rm CH_4}$  concentration. Because there are four regions and two variables (site  ${\rm CH_4}$  concentration and the percent of leaks >0.4 scfm  $[0.7~{\rm m^3~h^{-1}}]$ ), the likelihood that regional operating characteristics would coincidentally cause the increase in occurrence of leaks >0.4 scfm  $(0.7~{\rm m^3~h^{-1}})$  to mirror the increasing regional site  ${\rm CH_4}$  concentration is only one in 24 (four factorial), or ~4%.



Region and average wellhead CH<sub>4</sub> concentration

Figure 3. Occurrence of equipment leaks >0.4 scfm in each region of the [1] equipment leak data set. The odds of the occurrence of leaks >0.4 scfm being positively correlated with site CH <sub>4</sub> concentration are one in 24, which makes it unlikely this trend is due to regional operating effects.

Other known operating characteristics of the regions, such as average site pressure and average site age, are not related to the occurrence of equipment leaks >0.4 scfm (0.7 m $^3$  h $^{-1}$ ): average site pressures show no correlation, and average site age is negatively correlated with the occurrence of equipment leaks >0.4 scfm (0.7 m $^3$  h $^{-1}$ ).

Another argument against regional differences comes from the air quality study conducted by the City of Fort Worth ([6]; or the Ft. Worth study). Ft. Worth is part of the Mid-Continent region defined by [1], where the occurrence of equipment leaks only (as opposed to all BHFS measurement categories) >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) observed by [1] was 2.0% of the total equipment leaks in that region. However, equipment leaks >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) were 9.9% of the equipment leaks measured in the Ft. Worth study. This was determined using the Ft. Worth study categories of valves and connectors; their remaining category of "other", which included pneumatic control devices, had an even higher occurrence of sources >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) of 27.0%. Previous work [10] has shown that although sensor transition failure likely occurred in the Ft. Worth study, these incidents were limited compared to those in [1]. Consequently, the much lower occurrence of leaks >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) in the Mid-Continent region in [1] compared to the Ft. Worth study indicates that sensor transition failure was responsible for the low occurrence of emitters < 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) as opposed to regional differences.

### Gas density

Wellhead gas with a lower  $\mathrm{CH_4}$  and a greater heavier hydrocarbon content will be denser than gas with higher  $\mathrm{CH_4}$  content. Since gas flow through an opening is inversely related to the square root of the gas density, streams with lower  $\mathrm{CH_4}$  content would have a lower flow rate if all other conditions were the same. However, this would cause at most a 20% decrease for the lowest  $\mathrm{CH_4}/\mathrm{highest}$  heavier hydrocarbon streams compared to the highest  $\mathrm{CH_4}/\mathrm{lowest}$  heavier hydrocarbon streams observed in the UT study. This would also result in a gradual increase in emissions as  $\mathrm{CH_4}$  content increased, as opposed to the dramatic increase in emissions observed over a very narrow range of  $\mathrm{CH_4}$  concentrations (Fig. 2).

### **AVO** detection

AVO methods might improve for gas streams with a greater proportion of heavier hydrocarbons, since those streams would have greater odor and might leave more visible residue near a leak. However, Figure 4 presents the occurrence of emitters >0.4 scfm (0.7 m $^3$  h $^{-1}$ ) as a function of site CH $_4$  concentrations in the Appalachia

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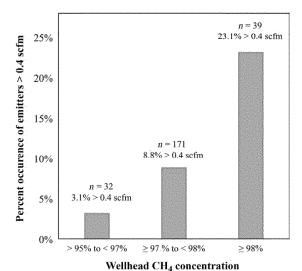


Figure 4. Occurrence of emitters >0.4 scfm as a function of site wellhead gas composition in [1] for the Appalachia region. An emission rate of greater than 0.4scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of 8scfm. The dramatic increase in emitters >0.4scfm over a narrow concentration range argues against the possibility that auditory, visual, and olfactory leak detection is the cause of the emission rate pattern seen in the [1] data set.

region alone. This region had the highest average CH<sub>4</sub> concentration in wellhead gas of any of the regions sampled in [1]. As seen in Figure 4, even over a very narrow range of site CH<sub>4</sub> concentrations (from 95% to >98%  $CH_{A}$ ), there is a dramatic increase in emitters >0.4 scfm  $(0.7 \text{ m}^3 \text{ h}^{-1})$  with increasing CH<sub>4</sub> concentration. It is unlikely that AVO methods would become so much more efficient over such a narrow range of high CH 4 concentrations where the gas streams are likely odorless and would leave little residue. This dramatic increase in high emitters at sites with high CH<sub>4</sub> concentrations within the Appalachia region alone also argues against the previously discussed regional operating differences hypothesis in general, since this trend is within a single region. Additionally, although the Rocky Mountain region surveyed by UT [1] had the lowest average site CH<sub>4</sub> concentration (74.9%) and heaviest hydrocarbon content, it actually had the highest number of equipment leaks (of any size) per well of all the regions, and there were 25% more leaks per well in that region than in the Appalachia region, which had the highest average site CH<sub>4</sub> concentration (97.0%) and therefore the lowest heavier hydrocarbon content. If AVO methods were more effective due to the presence of heavier hydrocarbons, it seems unlikely the region with the heaviest hydrocarbon concentrations would have the highest rate of overall leak occurrences.

### Field Testing of the UT BHFS

Because the trend in the [1] data was consistent with sensor transition failure in the BHFS and no other explanation seemed plausible, I partnered with UT to test the sampler used by [1]. During that field program, the UT sampler had a version of firmware earlier than version 3.03, and older firmware versions have been shown to exhibit sensor transition failure [10]. However, the possible effect of the sampler's firmware version on the sensor failure was not known before this testing of the UT sampler, and at the time of my testing its firmware had been upgraded to a custom version (3.04).

As previously explained, the BHFS uses a catalytic oxidation sensor to measure sample stream concentrations from 0% to  $\sim\!5\%$  NG, and a thermal conductivity sensor for concentrations from  $\sim\!5\%$  to 100% NG. The catalytic oxidation sensor is typically calibrated with 2.5% CH $_4$  in air and the thermal conductivity sensor is calibrated with 100% CH $_4$  [4]. The manufacturer recommends sensor calibration every 30 days, a process which adjusts the response of the instrument. The calibration may also be checked ("bump-tested") periodically by the user, which does not adjust the instrument response. It is important to note that the description of the BHFS sensor operation in the supplemental information of [1] is incorrect, as they state that:

[A] portion of the sample is drawn from the manifold and directed to a combustibles sensor that measures the sample's methane concentration in the range of 0.05–100% gas by volume. The combustibles sensor consists of a catalytic oxidizer, designed to convert all sampled hydrocarbons to  $\rm CO_2$  and water. A thermal conductivity sensor is then used to determine  $\rm CO_2$  concentration.

However, the BHFS manual [4] clearly states that the catalytic oxidation sensor is used to measure concentrations from 0% to 5%  ${\rm CH_4}$  and the thermal conductivity sensor from 5% to 100%  ${\rm CH_4}$ . This is a critical distinction because understanding that the BHFS uses a different sensor for each range and that it must transition from the catalytic oxidation sensor to the thermal conductivity sensor in order to conduct accurate measurements is critical to understanding the problem of sensor transition failure.

I initially conducted field testing of the UT sampler in conjunction with the UT team at a NG production site with a wellhead gas CH<sub>4</sub> concentration of 90.8%. NG composition analysis (via gas chromatograph-flameionization detector) of wellhead gas at this site was conducted by the host company just prior to the sampler testing. The tests were conducted by metering known flow rates of NG into the BHFS inlets through a rotameter (King Instrument Company, Garden Grove, CA; 0–10 scfm air

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scale). The sample concentration indicated by the internal BHFS sensor was recorded and compared to an external gas concentration monitor used to measure the actual NG concentration at the sampler exhaust (Bascom-Turner Gas Sentry CGA 201, Norwood, MA). The Gas Sentry unit was calibrated with 2.5% and 100%  ${\rm CH_4}$  prior to the testing; exhaust concentrations measured using this unit agreed with concentrations calculated using the sampler flow rate and amount of NG metered into the inlet to within an average of  $\pm 6\%$ .

This field testing was conducted in March of 2014 and is described by [10]; the UT sampler is identified therein as BHFS No. 3. At the time of this testing, the UT BHFS had firmwareVersion 3.04 (September 2013); this sampler had been calibrated 2 weeks prior to the fieldtest and had been used for emission measurements at production sites since that time. The response of the sensors was checked ("bump-tested") by the UT field team but not calibrated prior to the start of testing. This was apparently consistent with the UT fieldprogram methodology: the sampler had been used for measurements with only sensor bump tests, but without the actual calibration unless the sensors failed the bump tests (as was acceptable according to the manufacturer's guidelines) during their ongoing field measurement program and was provided to me for these measurements "ready for testing".

Although the UT sampler's internal sensors initially measured the sample concentration correctly, after ~20 min of testing the sampler's sensors failed to transition from the catalytic oxidation scale (<5% NG) to the thermal conductivity scale (>5% NG), resulting in sample concentration measurements that were 11-57 times lower than the actual sample concentration (Fig. 5). Because sample concentration is directly used to calculate emission measurements made by the sampler, this would result in emission measurements that are too low. After this sensor transition failure occurred, the UT BHFS was calibrated (not simply "bump-tested") and thereafter did not exhibit any further sensor transition failures even during a second day of testing at sites with wellhead CH<sub>4</sub> concentrations as low as 77%. Two other BHFS that were not part of the UT program were also tested using the same procedure: these instruments had the most updated firmware commercially available (Version 3.03) and were put through an actual calibration sequence by the instrument distributor's representative prior to any testing. Neither of these instruments exhibited sensor transition failure at any of the sites. These results combined with the sensor transition failure previously observed in instruments with earlier versions of firmware suggest that the combination of updated firmware and frequent actual calibrations might reduce sensor failure, although this has not been proved conclusively [10, 11].

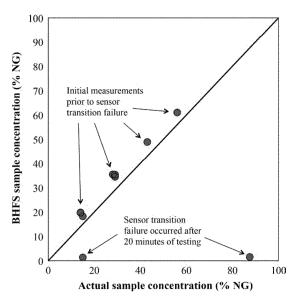


Figure 5. Performance of the BHFS used during the [1] study with NG composed of 90.8% CH<sub>4</sub>; instrument firmware had been upgraded to version 3.04 after that study but before this testing; calibration was 2 weeks old. Sensor transition failure set in after ~20min of testing; this failure was eliminated once the BHFS was put through a calibration sequence (as opposed to just a response test). BHFS, Bacharach HiFlow Sampler: NG, natural gas.

The UT recently published a follow-up study of pneumatic device emissions [2]. As part of this work, Allen et al. [2] conducted laboratory testing of the UT BHFS by making controlled releases of both 100% CH<sub>4</sub> and a test gas of 70.5% CH<sub>4</sub> mixed with heavier hydrocarbons into the UT BHFS and did not report any sensor transition failures during these tests, but during this laboratory testing the sampler (with the updated firmware version 3.04) was calibrated (not 'bump-tested") immediately prior to any testing. Consequently, the absence of sensor failure during their laboratory testing is consistent with the results observed during the March 2014 field tests, where calibrating the instrument eliminated the sensor failure.

Allen et al. [3] have suggested that the protocol during their field campaign was to check the calibration of the UT BHFS anytime it was turned on and that not following this protocol led to the sensor transition failure observed during this testing. However, in this instance, the sensor failure occurred both prior to and after the instrument was restarted. Additionally, the UT team observing the testing process did not suggest a calibration check when the instrument was turned back on for further testing. It was only after the sensor failure was observed that they checked and calibrated the instrument, so it

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does not appear that their protocol was to check the instrument calibration anytime it was turned on.

In summary, because the firmwarefor the UT sampler was updated prior to this testing (and therefore not the same as the version used during the UT field campaign [1]), and updated firmwaremay be a factor in reducing sensor failure, it is not expected that these test results are representative of how frequently sensor transition failure might have occurred during the UT study [1]. However, these results do clearly demonstrate that sensor transition failure could occur while using the UT BHFS.

### Comparison With Other Pneumatic Device Studies

Two other recent studies have measured emission rates from pneumatic devices by installing meters into the supply gas lines of the devices, as opposed to measuring emissions using the BHFS as was done by Allen et al. [1]. Prasino [22] used the meter installation technique to study emissions from pneumatic controllers in British Columbia, and the UT follow-up study [2] installed meters to measure emission rates from pneumatics in the four regions surveyed in the previous UT study [1].

Unfortunately, it is not possible to compare the pneumatic device emission factors from [1] to those from either the Prasino study, or from [2], because even though [1] sought to randomly sample pneumatic devices, the result was clearly an emitter data set (measurements focused on pneumatic devices that were emitting), while the Prasino data set was made with a random selection of devices and [2] made comprehensive measurements of all devices that could be measured safely at each site. This difference can be demonstrated by comparing the percentage of emitting intermittent pneumatic devices occurring in [1] to that in [2]. In [1], 95.3% (123 out of 129 intermittent devices) were greater than zero, with the smallest nonzero emitter equal to 0.12 scfh  $(0.0034 \text{ m}^3 \text{ h}^{-1})$ . In [2], only 57.5% (184 out of 320) intermittent devices) were greater than zero. This percentage of nonzero measurements drops further if the lowest nonzero emitter (0.12 scfh; 0.0034 m<sup>3</sup> h<sup>-1</sup>) observed by [1] is used as a threshold, in which case only 21.3% (68 out of 320) would be considered emitters. Since this threshold of 0.12 scfh (0.0034 m<sup>3</sup> h<sup>-1</sup>) is 25 times lower than the typical minimum range of the Fox FT2A meters by [2], the reported emitters below this threshold are most likely instrument noise caused by the meter's thermal elements inducing convection currents [7].

Consequently, although the intent of [1] was to survey randomly selected devices, their approach actually resulted in a data set comprised almost exclusively of emitting devices; this possibility is acknowledged by [2]. Therefore,

average emissions and emission factors for pneumatic devices calculated from [1] cannot be compared to those calculated from data collected by random or comprehensive sampling, such as presented in [22] or [2], because the emitter data set removes almost all the zero emitters and would result in much higher average emissions.

However, both [1] and [2] provide the  $\mathrm{CH_4}$  composition of the wellhead gas at the sites surveyed. This allows a comparison of emission rate patterns as a function of  $\mathrm{CH_4}$  concentration between devices measured by the BHFS [1] and by installed meters [2]. If the scarcity of high emitters measured by BHFS at sites with lower  $\mathrm{CH_4}$  concentrations in the initial UT study [1] was not an artifact caused by sensor transition failure, then the same concentration pattern should be present whether measured by the BHFS or by installed meters.

For this analysis, I removed the Rocky Mountain region to eliminate any bias from current or impending regulations that might have affected emission rates. Additionally, I focused on emissions from intermittent pneumatics because that provides the most complete data set from the two studies. Finally, as noted previously, the pneumatic device measurements from [1] apparently focused on emitting devices, whereas the devices surveyed in [2] were sampled as comprehensively as possible so the occurrences of high emitters in each study cannot be directly compared. Consequently, it is the ratio of the occurrences of high emitters at low CH<sub>4</sub> sites compared to high CH<sub>4</sub> sites within each study that must be compared.

As seen in Table 1, when measured by [1] via BHFS, the occurrence of emitters >0.4 scfm (0.7 m $^3$  h $^{-1}$ ) (on a percentage basis) at sites with wellhead gas compositions <91% CH $_4$  is almost a factor of five less than at sites with CH $_4$  >91%, consistent with BHFS sensor failure. Conversely, when measured via installed meters [2], the occurrence of emitters >0.4 scfm (0.7 m $^3$  h $^{-1}$ ) at sites with wellhead gas compositions <91% CH $_4$  is almost a factor of three higher than at sites with >91% CH $_4$ , indicating a complete reversal in this trend. This stark difference between BHFS measurements and installed meter measurements corroborates that the scarcity of high emitters at sites with lower wellhead gas CH $_4$  content present in [1] was an artifact due to sensor failure in the BHFS.

### Focused Analysis of the UT Study Equipment Leaks

In order to better understand the threshold of wellhead gas CH<sub>4</sub> concentrations at which sensor transition failure might occur, I conducted further analysis focused only on the equipment leak measurements in [1]. Equipment leaks were targeted because they are expected to be short term, steady state measurements, whereas emissions

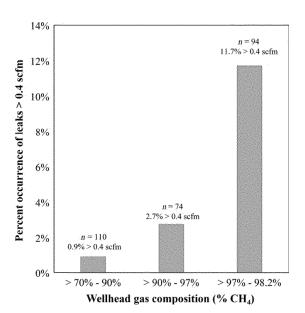
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Table 1. Occurrence of intermittent pneumatic device high emitters as a function of wellhead gas composition, measured by Bacharach Hi- Flow Sampler (BHFS) and installed meters (Rocky Mountain region excluded).

	No. of devices measured	No. of devices with emissions >0.4 scfm	% of devices with emissions >0.4 scfm
Allen et al. [1] (Measured by BHFS sampler)			
Wellhead gas composition >91% CH₄	85	28	32.9
Wellhead gas composition <91% CH <sub>2</sub>	44	3	6.8
Ratio of frequency of high emitters at sites with well wellhead gas compositions >91% CH <sub>4</sub>	head gas compositions <91% Ch	ቲ to sites with	0.21
Allen et al. [2] (Measured by installed meters)			
Wellhead gas composition >91% CH₄	106	3	2.8
Wellhead gas composition <91% CH <sub>2</sub>	97	8	8.2
Ratio of frequency of high emitters at sites with well wellhead gas compositions >91% CH <sub>4</sub>	head gas compositions <91% CF	ዛ <sub>4</sub> to sites with	2.9

reported from pneumatic devices and chemical injection pumps are likely to be an average of several measurements, and emissions from tanks may have an NG composition different from the reported wellhead composition.

Figure 6 presents the occurrence of equipment leaks in [1] that are >0.4 scfm (0.7 m³ h $^{-1}$ ) as a function of site CH $_4$  concentrations. At sites with gas compositions of >97% CH $_4$ , 11.7% of the leaks were >0.4 scfm (0.7 m³ h $^{-1}$ ). At sites with wellhead compositions between 90% and 97% CH $_4$ , only 2.7% of the leaks were >0.4 scfm



**Figure 6.** Occurrence of equipment leaks >0.4scfm as a function of site well head gas CH <sub>4</sub> content in the [1] study. Leaks >0.4 scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of &scfm. The large increase in the occurrence of leaks >0.4 scfm at sites with CH<sub>4</sub> content >97% indicates sensor transition failure below that threshold.

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(0.7 m³ h<sup>-1</sup>), and this occurrence dropped to less than 1% at sites with wellhead gas compositions of <90% CH<sub>4</sub>, indicating that the sampler's ability to measure leaks >0.4 scfm (0.7 m³ h<sup>-1</sup>) declined dramatically with decreasing concentrations of CH<sub>4</sub> in the wellhead gas (Fig. 6). This analysis indicates the BHFS may underreport emitters >0.4 scfm (0.7 m³ h<sup>-1</sup>) even when making measurements of NG streams with CH<sub>4</sub> content up to 97%, and provides a valuable refinement of the possible CH  $_4$  concentration threshold where sensor failure may occur, since the highest CH<sub>4</sub> wellhead content available for direct field testing of the BHFS was only 91.8%.

### Comparison of the UT Study Downwind Tracer Ratio Measurements to On-Site Measurements

Allen et al. [1] also made emission measurements using a downwind tracer ratio method at 19 sites for comparison to their on-site measurements. Their emissions from onsite measurements were calculated by using direct measurements of equipment leaks and pneumatic devices that were made by the UT team combined with estimates of emissions from any sources at the well pad that were not measured. These unmeasured sources included all tanks and compressors (compressors were a small source in comparison to all other sources) as well as any pneumatics that was not directly measured during the site survey. For CH<sub>4</sub> emissions from tanks and compressors, the authors used "standard emissions estimation methods" [1]. For pneumatic devices that were not surveyed, they applied their own emission factors based on the measurements of pneumatic devices collected during the UT study.

The tracer ratio measurements were made by releasing a tracer gas at a known rate to simulate the emissions from the site being measured. Simultaneous downwind measurements were then made of the concentrations of both the tracer gas and  $CH_4$ , and then the emission rate

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of  $\mathrm{CH_4}$  was calculated after correcting for background  $\mathrm{CH_4}$  and tracer concentrations. The tracer ratio method allows for the calculation of  $\mathrm{CH_4}$  emissions from the entire production site by accounting for the dilution of  $\mathrm{CH_4}$  as it is transported into the atmosphere from the source to the receptor.

In summarizing their tracer ratio measurements, [1] state: "For the production sites, emissions estimated based on the downwind measurements were also comparable to total on-site measurements; however, because the total on-site emissions were determined by using a combination of measurements and estimation methods, it is difficult to use downwind measurements to confirm the direct source measurements." However, upon further examination, I found that the downwind tracer measurements do in fact indicate the occurrence of sensor transition failure in their BHFS measurements.

Table 2 summarizes the characteristics of the sites surveyed by [1] using both the BHFS and the tracer ratio method. As described above, the on-site total is a combination of the measurements made by BHFS and estimates for any sources not actually measured by the UT team. I calculated the ratio of actual BHFS measurements to

the total reported on-site emissions (estimated and measured) using the supplemental information provided by [1]. Actual measured emissions ranged from 1% to 79% of the total reported on-site emissions and the on-site total emissions range from 13% to 3500% of the downwind tracer ratio measurements (Table 2).

Table 3 compares the tracer ratio measurements to the on-site emissions, categorized by  ${\rm CH_4}$  content in the well-head gas and by the fraction of actual BHFS measurements that comprise the on-site emissions. As shown in Table 3, when comparing all sites without separating them into these categories, the total of the tracer ratio measurements does agree closely to the on-site emissions, as [1] concluded. However, four of the sites had wellhead gas compositions of  $\geq$ 97%  ${\rm CH_4}$ , at which the BHFS would be expected to make accurate measurements. The remaining 15 sites had wellhead gas compositions of <82%  ${\rm CH_4}$ , at which sensor transition failure might occur and the BHFS would underreport emissions measurements.

Once the sites are categorized by these wellhead gas compositions, a deficit between the on-site emissions and the tracer ratio measurements appears in sites with lower  $CH_A$  concentrations, and this deficit becomes more

Table 2. Sites surveyed by Allen et al. [1] using both Bacharach Hi-Flow Sampler (BHFS) and downwind tracer methods.

Tracer site name <sup>1</sup>	BHFS site name <sup>1</sup>	Wellhead gas CH <sub>4</sub> concentration (%)	On-site total <sup>2</sup> (BHFS measurements and estimates) (scfm CH <sub>4</sub> )	BHFS measure- ments/on-site total <sup>3</sup>	Leaks measured by BHFS/on-site total <sup>3</sup>	Tracer ratio emission rate (scfm CH <sub>4</sub> )	On-site total/ tracer ratio emission rate
MC-1	MC-1	70.9	1.89	0.12	0.12	2.32	0.815
MC-2	MC-14	78.1	0.99	0.34	0.01	2.00	0.495
MC-3	MC-20	77.2	1.63	0.45	0.18	2.95	0.552
MC-4	MC-5	74.2	2.31	0.19	0.14	3.36	0.687
MC-5	MC-16	79.3	1.85	0.56	0.18	4.16	0.445
RM-1	RM-7	81.9	0.22	0.11	0.09	0.584	0.368
RM-2	RM-8	74.5	4.43	0.02	0.02	1.70	2.60
RM-3	RM-1	76.4	0.13	0.67	0.69	0.442	0.303
RM-4	RM-3	74.9	0.11	0.21	0.00	0.839	0.137
RM-5	RM-2	74.5	0.09	0.35	0.33	0.240	0.392
RM-6	RM-5	74.5	0.74	0.41	0.42	0.421	1.75
RM-7	RM-14	74.5	0.27	0.26	0.26	0.368	0.736
RM-8	RM-19	76.2	0.29	0.82	0.79	1.08	0.266
RM-9	RM-12	74.5	0.38	0.05	0.05	0.864	0.436
RM-10	RM-4	76.2	2.86	0.01	0.00	0.080	35.7
AP-2	AP-23	97.6	1.28	0.68	0.35	0.270	4.74
AP-3	AP-43	97.0	4.75	0.62	0.59	4.12	1.15
AP-4	AP-37	97.0	1.36	0.44	0.42	0.709	1.92
AP-5	AP-18	97.0	0.39	0.74	0.69	0.288	1.37

<sup>&</sup>lt;sup>1</sup>MC, Midcontinent; RM, Rocky Mountain; AP, Appalachia. Different site numbers were used to identify the same sites in the [1] supplemental information depending on whether BHFS or tracer ratio measurements were under discussion.

<sup>&</sup>lt;sup>2</sup>On-site totals were calculated by [1] by combining measurements made by the BHFS with estimates of any sources not measured; these estimates were made using mathematical models for tanks as well as emission factors for compressors and any pneumatic controllers not directly measured. <sup>3</sup>Calculated by this author from [1] supplemental information.

pronounced as the amount of the on-site emissions actually measured by the BHFS becomes a larger fraction of the total on-site emissions (measured and estimated). As seen in Table 3, for the high CH<sub>4</sub> sites where the sampler should function properly, the on-site measurements and estimates exceed the tracer measurements, but approach a ratio of one (complete agreement) as the amount of actual measurements increases. For the two sites with wellhead gas compositions ≥97% where the measured equipment leaks (which should produce steady emissions as compared to pneumatic devices which might be intermittent) averaged 64% of the total on-site measurements and estimates, the on-site total still exceeds the tracer measurements but are within 17% (Table 3). However, for the sites with wellhead gas  ${\rm CH_4}$  concentrations <82%, there is a clear trend of increasing deficit of the on-site emissions compared to the tracer ratio measurements as the actual BHFS measurements become a larger part of the on-site total. For instance, for the nine sites with at least 20% of on-site emissions from BHFS measurements (for an average of 45% of the total on-site emissions measured by the BHFS), the on-site emissions are only 49% of the tracer measurements (Table 3). For the two sites that had greater than 67% of on-site emissions data actually measured by the BHFS (for an average of 75% of on-site emissions data measured by the BHFS), the on-site emissions are only 28% of the tracer measurements (Table 3).

Comparing the on-site data to the downwind tracer measurements provides two valuable insights. First, there were six sites in the Rocky Mountain region for which at least 20% of the on-site emissions were measured by the BHFS (for an average of 45% actual BHFS measurements) (Table 2). For these six sites, the on-site emissions average 48% of the tracer data. For the two sites in this

region with at least 67% of on-site emissions from actual BHFS measurements (and with BHFS measurements averaging 75% of the total on-site data), the on-site emissions were only 28% of the tracer measurements (Table 2). This provides clear evidence that the sampler actually did fail in the Rocky Mountain region, as opposed to any possible regional differences (discussed previously) that might have created an emission pattern of no high emitters at sites with lower  ${\rm CH_4}$  concentrations in the wellhead gas.

Additionally, the tracer measurements provide a method to estimate the magnitude of errors introduced in the data collected by [1] due to BHFS sensor transition failure. For all of the sites with wellhead gas compositions ≥97% CH<sub>4</sub> (where the sampler should operate correctly), the emission rates determined by on-site measurements exceeded those determined by the downwind tracer ratio measurements. Assuming that the tracer method accurately measured the total emissions from the sites surveyed (e.g., [8, 15, 16]), I concluded that the methods used in [1] overestimated the on-site sources that were not directly measured. Therefore, I calculated the error in BHFS measurements at sites with low CH<sub>4</sub> wellhead gas composition by assuming the tracer ratio measurements are correct. I have also assumed for this analysis that the estimates of any onsite sources made by [1] are also correct, even though the tracer data indicate they may be too high, because this is conservative in the sense that correcting for this overestimate would increase the BHFS error calculated below. Given these assumptions, subtracting the on-site estimated emissions from the tracer ratio emissions gives the expected measurement total that should have been reported from the BHFS measurements. Comparing this expected measurement total to the actual

Table 3. Comparison of on-site measurements to tracer ratio measurements made by Allen et al. [1] categorized by wellhead gas CH<sub>4</sub> concentration.

Site category (number of sites in parentheses)	Average percentage of on-site emissions reported by BHFS	Total on-site emissions (reported by BHFS and estimated) (scfm CH <sub>4</sub> )	Total emissions measured by tracer (scfm CH <sub>4</sub> )	Ratio of on-site emissions to emissions measured by tracer
All sites (19)	37	26.0	26.8	0.97
Sites where BHFS measurements are expected	to be accurate (wellhead	gas composition ≥97% CH	<u>4</u> )	
All sites (4)	62	7.78	5.39	1.44
Sites with >50% BHFS measurements (3)	68	6.42	4.68	1.37
Sites with >50% equipment leaks (2)	64 (equipment leaks/on-site total)	5.14	4.41	1.17
Sites where BHFS measurements are expected	to underreport high emit	ters (wellhead gas composi	tion <82% CH <sub>a</sub> )	
All sites (15)	28	18.2	21.4	0.85
Sites with ≥5% BHFS measurements (13)	35	10.9	19.6	0.56
Sites with ≥20% BHFS measurements (9)	45	6.10	12.5	0.49
Sites with >50% BHFS measurements (3)	69	2.27	5.68	0.40
Sites with >67% BHFS measurements (2)	75	0.42	1.52	0.28

BHFS, Bacharach Hi-Flow Sampler.

T. Howard

measurement total reported by the BHFS provides an estimate of the error in BHFS measurements made by Allen et al. [1].

Table 4 presents the results of this analysis, and shows that for the 13 sites with wellhead gas compositions <82% CH<sub>4</sub> and with at least 5% actual BHFS measurements (with an average of 35% of emission sources measured by BHFS; bottom half of Table 3), the actual measurement total of the BHFS is less than one-third of the expected total, and this appears consistent as sites with greater fractions of actual BHFS measurements are examined. For these sites, the emission rates for equipment leaks and pneumatics devices presented by [1] are approximately equal, so it is not possible to assign a larger error to one category or another. Additionally, the errors introduced by the sensor failure would be expected to vary from site to site depending on how many emitters were present with emission rates exceeding the sensor transition threshold ceiling. Nevertheless, for these 13 sites, the BHFS underreported emissions for equipment leaks and pneumatic devices on average by more than a factor of 3 (Table 4).

Although the magnitude of error due to BHFS sensor failure is not known for all the sites in [1], the tracer ratio measurements make clear that the BHFS measurements for sites with lower CH<sub>4</sub> content in the wellhead gas could be at least a factor of three too low. More precise estimates of errors in [1] are not possible because of the nature of the sensor failure. Unlike a simple calibration error, for which it might be possible to correct, when sensor transition failure occurs, it is not possible to know for any particular measurement if the failure has occurred, and if it has, what the resulting error was, since the reported emission rates could range from 20% to two orders of magnitude too low.

### **Implications**

Sensor transition failure is clearly apparent in the BHFS measurements made in the UT study by Allen et al. [1], as evidenced by the rare occurrence of high emitters at sites with lower CH<sub>4</sub> (<91%) content in the wellhead gas. The occurrence of this sensor transition failure was corroborated by fieldtests of the UT BHFS during which it exhibited this sensor failure, as well as by tracer ratio measurements made by [1] at a subset of sites with lower wellhead gas CH4 concentrations. At this subset of sites, the tracer ratio measurements indicate that the BHFS measurements were too low by at least a factor of three. Because BHFS measurements were the basis of 98% of the inventory developed by [1] using their own measurements (and 41% of their total compiled inventory), the inventory clearly underestimates CH<sub>4</sub> emissions from production sites. However, the extent of this error is difficult to estimate because the underreporting of emission rates due to BHFS sensor transition failure at any given site would vary depending on sampler performance and on how many high emitters were present at that site. Estimating this error is further complicated by the fact that the data set collected for pneumatic devices by [1] was an emitter data set; this might offset the effect of underreported high emitters in their pneumatic device emission factors. Finally, although real differences may exist in regional emission rates, the UT data set [1] should not be used to characterize them because the occurrence of sensor failure clearly varied between regions due to variations in wellhead CH₄ compositions, which may mask any actual regional differences that existed.

Although the performance of the BHFS may vary between instruments or with sensor age or calibration vintage, this analysis of the [1] data set shows that measurements made using a BHFS for NG streams with  $CH_4$  content

**Table 4.** Estimation of underreporting in Allen et al. [1] BHFS measurements of CH<sub>4</sub> emission rates at sites with low CH<sub>4</sub> well head gas composition (<82%), using downwind tracer measurements (from Table 3).

Minimum percentage of on-site emissions reported by BHFS	Average percentage of on-site emissions reported by BHFS	No. of sites	Total emissions measured by tracer (scfm CH <sub>4</sub> )	On-site emissions estimated by UT (excludes BHFS measure- ments) (scfm CH <sub>4</sub> )	Expected BHFS measurement total (tracer – on-site estimates) (scfm CH <sub>4</sub> )	Emissions reported by BHFS (sofm CH <sub>4</sub> )	Ratio of reported BHFS to expected BHFS
≥5	35	13	19.63	7.09	12.54	3.81	0.30
≥20	45	9	12.50	3.34	9.16	2.76	0.30
>50	69	3	5.68	0.71	4.97	1.56	0.31
>67	75	2	1.52	0.11	1.42	0.31	0.22

BHFS, Bacharach Hi-Flow Sampler; UT, University of Texas.

UT Study Underestimates Methane Emissions

up to 97% could lead to severe underreporting of NG leaks. That this failure can occur at such high  $\mathrm{CH_4}$  concentrations, which are close to the higher end of those found in transmission and distribution systems, indicates that past measurements in all segments of the NG supply chain could have been affected by this problem. Because the BHFS sensor transition failure phenomenon is not fully understood, it is not known how much this error may have affected past measurements of  $\mathrm{CH_4}$  emission rates. Two factors preclude this: first, the performance of any individual BHFS may vary, and second, once sensor transition failure occurs, there is no way to determine the magnitude of the measurement error in the absence of an independent flux or concentration measurement.

If BHFS sensor transition failure has occurred during industry monitoring at transmission, storage, and processing compressor stations where the BHFS is approved for leak measurements mandated by the USEPA Subpart W Greenhouse Gas Reporting Program (GHGRP) [23], then these errors could be larger than those observed at production sites. Leaks at transmission, storage, and processing compressor stations commonly exceed 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) (the approximate threshold for BHFS sensor transition failure) and in some cases may range from 10 to over 100 scfm. Because the largest 10% of leaks typically account for 60-85% of the total leak rate at a given facility [9, 25], sensor transition failure in the BHFS could bias CH4 emission inventories compiled by the USEPA GHGRP substantially low since the most significant leaks could be underreported. Additionally, leak measurements using the BHFS may be used to guide repair decisions at NG facilities, and underreporting of leaks could compromise safety if large leaks remain unrepaired as a result.

Finally, it is important to note that the BHFS sensor failure in the UT study [1] went undetected in spite of the clear artifact that it created in the emission rate trend as a function of wellhead gas CH<sub>4</sub> content and even though the authors' own secondary measurements made by the downwind tracer ratio technique confirmed the BHFS sensor failure. That such an obvious problem could escape notice in this high profile, landmark study highlights the need for increased vigilance in all aspects of quality assurance for all CH<sub>4</sub> emission rate measurement programs.

### Acknowledgments

The author thanks Dave Allen (University of Texas at Austin) for making the UT BHFS available for field testing, and Adam Pacsi (University of Texas at Austin), Matt Harrison and Dave Maxwell (URS Corporation), and Tom Ferrara (Conestoga Rovers & Associates) for their assistance

with the field testing of the BHFS. This paper was substantially improved by the comments of three anonymous reviewers.

### **Conflict of Interest**

The author is the developer of high flowsampling technology (US Patent RE37, 403) and holds a license to use it for any purpose; however, he does not sell high flow samplers nor was he involved in the development of the Bacharach Hi-Flow Sampler.

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**To:** Macpherson, Alex[Macpherson.Alex@epa.gov]; Hambrick, Amy[Hambrick.Amy@epa.gov]; Thompson, Lisa[Thompson.Lisa@epa.gov]; Thoma, Eben[Thoma.Eben@epa.gov]; Snyder, Jennifer[Snyder.Jennifer@epa.gov]

From: Weitz, Melissa

**Sent:** Mon 11/30/2015 7:18:31 PM

Subject: FW: OAR-16-000-1201 - Letter Argues Instrument Incorrectly Measures Methane Emissions

OAR-16-000-1201THoward MthnMsrmntToolWrng incmng 11-12-15.pdf

Howard Hi Flow letter response 11 30.doc

Hello,

Janet received a letter from Touche Howard on the Hi Flow sampler issue.

The attached PDF includes Touche's letter (~1 page) and his two articles, which he appended to the letter.

My draft response (~1 page) is in the attached word document. It basically notes that we are aware of Touche's articles on the hi flow, are currently evaluating a number of data sources for our GHG estimates, and that we are willing to meet with him.

If anyone would like to review and has edits or comments, please send them to me by COB tomorrow. I'm also happy to answer any questions-just let me know.

Thank you!

Melissa

From: Hargrove, Anne

Sent: Thursday, November 12, 2015 12:07 PM

To: Franklin, Pamela < Franklin.Pamela@epa.gov >
Cc: Briscoe, Earline < Briscoe. Earline@epa.gov >

**Subject:** OAR-16-000-1201 - Letter Argues Instrument Incorrectly Measures Methane Emissions

OAR-16-000-1201

Hi Pamela:

Attached you will find an incoming letter from Howard Touche to Janet. Touche argues that the Bacharach Hi-Flow Sampler (BHFS) seriously under-reports methane emission leak rates that occur in natural gas production. He also has attached to his letter two papers on this subject.

If you think your branch is the correct place to respond to this control, please let me know what kind of extension you will need to produce a draft. The response is to be signed by Sarah. If this letter should be handled by a different branch, please let me know right away. I think you may need an extension because the current due date is Nov. 18, which means we would have to get it at the very latest by the end of the day Monday Nov. 16, which seems unreasonable.

If you think the response should involve collaboration with other branches, I can send this email to whomever you designate.

In addition to the incoming correspondence, I have attached the information sheet for this control, in case you need further information about it. Also, I've attached a sample response letter you should use to format your response.

Thank you,

Anne Hargrove

Climate Change Division

U.S. Environmental Protection Agency

(202) 343-9926

To: Irving, Bill[Irving.Bill@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; McKittrick,

Alexis[McKittrick.Alexis@epa.gov]; Thoma, Eben[Thoma.Eben@epa.gov]

From: Weitz, Melissa

**Sent:** Fri 2/12/2016 8:12:24 PM

Subject: FW: Meeting on Hi-Flo Sampler with Touché Howard

I gave Matt a quick call to thank him for the offer and to let him know we'd get back to him in the next week or so to let him know if we'd like written comments (potentially on the GHGI memos where we ask about this issue), or if we'd like to set up a call to discuss, etc.

Thoughts? I like the approach of responding to the GHGI memo request for feedback on this.

From: Harrison, Matt [mailto:matt.harrison@aecom.com]

Sent: Thursday, February 11, 2016 3:49 PM

To: McKittrick, Alexis <IMCEAMAILTO-McKittrick+2EAlexis+40epa+2Egov@URS.COM>;

Weitz, Melissa <Weitz.Melissa@epa.gov>

Cc: Shires, Terri <terri.shires@aecom.com>; Thoma, Eben <Thoma.Eben@epa.gov>;

DeFigueiredo, Mark < DeFigueiredo. Mark@epa.gov > **Subject**: Meeting on Hi-Flo Sampler with Touché Howard

Dear Alexis and Melissa,

I heard the web presentation made by Mr. Touche Howard when he visited EPA last Friday 2/5/16. Mr. Howard invited me to attend. Thank you for allowing me to listen in. I was surprised by the presence of press at the meeting.

If EPA would like a technical response from the UT-EDF authors to his theories and criticisms, I believe the PI and myself would be happy to discuss that with EPA. Alternately, we can send you some written comments, if you prefer.

Bottom line, while Mr. Howard has some good observations, he has not characterized all the facts appropriately.

If you need an official response, we would like to have the slide deck he presented and shared at your web meeting. Alexis, as your note to Terri Shires suggested, I have requested a copy of

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the slides from Mr. Howard, but have not received any response to that request.
Let me know if you care to discuss this further.
Thank you, Matt

Matthew Harrison, P.E.

Vice President

Americas - Upstream Oil & Gas

matt.harrison@AECOM.com

512-694-0572

### **AECOM**

9400 Amberglen Blvd., Austin, Texas 78729

www.aecom.com

From: McKittrick, Alexis [mailto:McKittrick.Alexis@epa.gov]

Sent: Tuesday, February 09, 2016 2:12 PM

To: Shires, Terri Cc: Harrison, Matt

Subject: RE: meeting on Hi-Flo Sampler with Touché Howard

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Attendees of this meeting who are not affiliated with the EPA should contact Touche Howard directly for copies of the slides.

Thanks,

Alexis

From: Shires, Terri [mailto:terri.shires@aecom.com]

Sent: Tuesday, February 09, 2016 9:26 AM

**To:** McKittrick, Alexis < <a href="mailto:McKittrick.Alexis@epa.gov">McKittrick.Alexis@epa.gov</a> <a href="mailto:Cc:Harrison, Matt">Cc: Harrison, Matt < <a href="mailto:matt.harrison@aecom.com">matt.harrison@aecom.com</a> <a href="mailto:matt.harrison.harris

Subject: RE: meeting on Hi-Flo Sampler with Touché Howard

Alexis.

Could you please distribute the slides that Touché' presented last week?

Thank you,

### **Terri Shires**

Senior Engineer and Project Manager, Design and Construction Services, Gulf Coast Region D +1-512-419-5466 M +1-512-497-6482 Terri.Shires@aecom.com

### **AECOM**

9400 Amberglen Blvd. Austin, Texas 78729, USA T +1-512-454-4797 aecom.com

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From: McKittrick, Alexis [mailto:McKittrick.Alexis@epa.gov]

Sent: Friday, February 05, 2016 12:56 PM

To: ralvarez@edf.org; lisa.song@insideclimatenews.org; nancy@ncwarn.org; Shires, Terri

Subject: Fwd: meeting on Hi-Flo Sampler with Touche Howard

Sent from my iPhone

https://epawebconferencing.acms.com/r2fk2tdpn9x/

From: Weitz, Melissa

Sent: Wednesday, December 23, 2015 4:35 PM

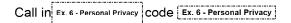
To: Weitz, Melissa; DeFigueiredo, Mark; Waltzer, Suzanne; McKittrick, Alexis;

Macpherson, Alex; Moore, Bruce; Thoma, Eben; Thompson, Lisa; Hambrick, Amy; Banks,

Julius; Irving, Bill **Cc:** Howard, Jodi

Subject: meeting on Hi-Flo Sampler with Touche Howard

When: Friday, February 5, 2016 1:30 PM-2:30 PM. Where: DCRoomWJCS4228AOAP/DC-OAR-OAP



A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

October 26, 2015

Acting Assistant Administrator Janet McCabe Office of Air and Radiation **USEPA Headquarters** William Jefferson Clinton Building 1200 Pennsylvania Avenue, N. W. Mail Code: 6101A Washington, DC 20460

McCabe.janet@Epa.gov

Via Certified Mail and Email

Dear Ms. McCabe:

Over the past two years I have been investigating a problem with the Bacharach Hi-Flow Sampler (BHFS) which causes it to underreport natural gas emission rates. The BHFS is used to make measurements of individual leak rates of natural gas, and has been used for many applications, including compiling emissions inventories as well as making decisions on which leaks should be repaired based on safety and cost. This instrument is also approved for making emissions measurements required under the EPA Greenhouse Gas Reporting rule, and is the only commercial instrument available to make such measurements.

Although we don't know how widespread this problem might be, it's clear that its occurrence may be significant. I've attached two papers on the topic. The first details testing of several samplers under controlled conditions, during which this failure occurred primarily with instruments that had an older generation of firmware, although failure was also observed in an instrument with newer firmware as well.

The second paper analyzes the University of Texas EDF production data set, which provides an excellent data set to examine this problem. Although it was initially thought that the problem might occur primarily when natural gas compositions were less than 91% methane, the analysis of the UT data set indicates clear failure even when natural gas compositions are as high as 97% methane. This means that measurements might be affected in all segments of the natural gas industry - production, processing, transmission, and distribution - and this has huge implications for safety, health, and the environment.

I would appreciate the opportunity to meet with you to discuss this further, because it's critical that this issue be disclosed and addressed as quickly as possible.

Regards,

Touché Howard

4900 Highway 55, Suite 160-314

Durham, NC 27713

(919) 943-9406

touchehoward@earthlink.net

### TECHNICAL PAPER

### Sensor transition failure in the high flow sampler: Implications for methane emission inventories of natural gas infrastructure

Touché Howard, <sup>1</sup> Thomas W. Ferrara, <sup>2,\*</sup> and Amy Townsend-Small<sup>3</sup>

<sup>1</sup>Indaco Air Quality Services. Inc., Durham. NC, USA

Please address correspondence to: Thomas W. Ferrara, Conestoga-Rovers & Associates, 2055 Niagara Falls Blvd., Niagara Falls, NY 14304, USA; e-mail: tferrara@craworld.com

Quantification of leaks from natural gas (NG) infrastructure is a key step in reducing emissions of the greenhouse gas methane (CH<sub>4</sub>), particularly as NG becomes a larger component of domestic energy supply. The U.S. Environmental Protection Agency (EPA) requires measurement and reporting of emissions of CH<sub>4</sub> from NG transmission, storage, and processing facilities, and the high-flow sampler (or high-volume sampler) is one of the tools approved for this by the EPA. The Bacharach Hi-Flow Sampler (BHFS) is the only commercially available high-flow instrument, and it is also used throughout the NG supply chain for directed inspection and maintenance, emission factor development, and greenhouse gas reduction programs. Here we document failure of the BHFS to transition from a catalytic oxidation sensor used to measure low NG (~5% or less) concentrations to a thermal conductivity sensor for higher concentrations (from ~5% to 100%), resulting in underestimation of NG emission rates. Our analysis includes both our own field testing and analysis of data from two other studies (Modrak et al., 2012; City of Fort Worth, 2011). Although this failure is not completely understood, and although we do not know if all BHFS models are similarly affected, sensor transition failure has been observed under one or more of these conditions: (1) Calibration is more than ~2 weeks old; (2) firmware is out of date; or (3) the composition of the NG source is less than ~91% CH<sub>4</sub>. The extent to which this issue has affected recent emission studies is uncertain, but the analysis presented here suggests that the problem could be widespread. Furthermore, it is critical that this problem be resolved before the onset of regulations on CH<sub>4</sub> emissions from the oil and gas industry, as the BHFS is a popular instrument for these measurements.

Implications: An instrument commonly used to measure leaks in natural gas infrastructure has a critical sensor transition failure issue that results in underestimation of leaks, with implications for greenhouse gas emissions estimates as well as safety.

### Introduction

Fugitive emissions of methane (CH<sub>4</sub>) from natural gas (NG) extraction, processing, transmission, and distribution are among the largest anthropogenic sources of CH<sub>4</sub> globally (Kirschke et al., 2013) and in the United States (U.S. Environmental Protection Agency [EPA], 2014). Emissions of CH<sub>4</sub> may increase as the United States and other nations exploit NG from shale (via hydraulic fracturing or "fracking") to replace coal and oil. Because CH<sub>4</sub> is a greenhouse gas 28 to 34 times more powerful than carbon dioxide (CO<sub>2</sub>) on a 100-year time scale (Myhre et al., 2013), increases in NG infrastructure due to this transition may increase regional or global greenhouse gas emissions, despite the fact that burning NG emits less CO<sub>2</sub> per unit of energy returned than coal or oil (Howarth et al., 2011; Wigley, 2011).

The Bacharach Hi-Flow Sampler (BHFS; Bacharach, Inc., New Kensington, PA), the only commercially available version of the high-flow sampler (sometimes also referred to as the "high-volume sampler"), was brought to market in 2001. Since

then, the instrument's use has broadened from the transmission, storage, and distribution segments to include increased use in production, and it has been used to measure NG emission rates from sources throughout the NG supply chain (Allen et al., 2013, 2014; American Carbon Registry [ACR], 2010; City of Fort Worth, 2011; Gas Technology Institute [GTI], 2013; Modrak et al., 2012; EPA 2006; U.S. Bureau of Land Management [BLM], 2011). The high-flow sampler is also one of the methods approved by the U.S. Environmental Protection Agency (EPA) for mandated measurements of NG leaks from transmission, storage, and processing facilities (Code of Federal Regulations [CFR], 2010). However, at least one previous study has found that this sampler may underreport emission rates by as much as two orders of magnitude when used to measure NG streams with <95% CH<sub>4</sub> such as commonly found at production sites (Modrak et al., 2012). Additionally, there is increasing evidence that ground-based (or "bottom-up") estimates of CH<sub>4</sub> emissions underreport emissions when compared to "top-down" estimates, thought to be due to erroneously low emissions

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<sup>&</sup>lt;sup>2</sup>Conestoga-Rovers & Associates, Niagara Falls, NY, USA

<sup>&</sup>lt;sup>3</sup>Department of Geology, University of Cincinnati, Cincinnati, OH, USA

factors reported for NG systems, resulting in low "bottom-up" estimates (Miller et al., 2013; Brandt et al., 2014).

The high-flow-rate sampling technique uses a high flow rate of air and a loose enclosure to completely capture the NG emitting from a source (Indaco, 1995; Howard, 2001). The emission rate is calculated as follows:

$$Q_{NG} = F_{sampler} \ x \ (C_{sample} - C_{background})/R \tag{1}$$

where  $Q_{NG}$  is the emission rate of NG from the source (scfm),  $F_{sampler}$  is the sample flow rate of the sampler (scfm),  $C_{sample}$  is the concentration of NG in the sample flow (%NG) indicated by the BHFS,  $C_{background}$  is the concentration of NG in the background near the component (%NG) indicated by the BHFS, and R is the response factor of the instrument (see later description for an explanation of response factor).

The BHFS uses a catalytic oxidation sensor to measure concentrations from 0% to approximately 5% NG, and a thermal conductivity sensor for concentrations from approximately 5% to 100% NG. The catalytic oxidation sensor is typically calibrated with 2.5% CH<sub>4</sub> in air and the thermal conductivity sensor is calibrated with 100% CH4 (Bacharach, 2010). Both sensors primarily respond to CH<sub>4</sub> and, to a lesser extent, ethane (C<sub>2</sub>H<sub>6</sub>), but have a lower response to heavier hydrocarbons and nonhydrocarbons. A response factor correction is necessary to account for differences between the calibration gas, which consists of only CH4, and the NG being sampled, which can have other hydrocarbons in addition to CH<sub>4</sub>. For example, if the instrument indicates a concentration of 80% NG in the presence of 100% NG, then the response factor is 0.8. Actual concentration is calculated by dividing the indicated concentration by the response factor. The response factors for the catalytic oxidation sensor and the thermal conductivity sensor might differ from each other for the same composition of NG, depending on which components of NG other than CH4 are present.

The manufacturer recommends sensor calibration every 30 days, either by shipping the instrument to a service center or by the user (Bacharach, 2010). The calibration may also be checked ("bump-tested") periodically by the user. Both procedures involve introducing the calibration standards to the instrument, but an actual calibration adjusts the gain of the calibration amplifier as needed, while the bump test only indicates the response of the sensor compared to the known concentration of the calibration gas (Bacharach, 2010).

Here we detail the results of a testing program conducted to understand the effects of NG composition, calibration status, and firmware status on the BHFS. We also present a reanalysis of recently published data on CH<sub>4</sub> emissions from NG production sites, and demonstrate that the instrument likely failed at some of those testing sites (Modrak et al., 2012; City of Fort Worth, 2011).

### Methods

In order to investigate the performance of the BHFS, field testing was conducted at five different NG production sites with wellhead gas CH<sub>4</sub> concentrations ranging from 66% to

90.8%. A summary of the field tests is shown in Table 1; the compositions of the NG streams at the production sites are shown in Table 2. NG sampling and composition analyses were (via gas chromatograph-flame ionization detector [GC-FID]) were conducted by the host company just prior to the sampler testing. We also conducted a laboratory test using commercial-grade CH<sub>4</sub> (> 99.9%).

The tests were conducted by metering known flow rates of NG into the sampler inlets through a rotameter (King Instrument Company, Garden Grove, CA; 0 to 10 scfm air scale). The sample concentration indicated by the internal BHFS sensor was recorded and compared to an external gas concentration monitor used to measure the actual NG concentration at the sampler exhaust (Bascom-Turner Gas Sentry CGA 201, Norwood, MA). The Gas Sentry unit was calibrated with 2.5% and 100% CH<sub>4</sub> prior to each field day; exhaust concentrations measured using this unit differed from calculated concentrations (calculated using the sampler flow rate and amount of NG metered into the inlet) by an average of ±6%.

Five samplers were tested during this program at 5 sites with varying NG compositions (Tables 1 and 2). Samplers 1 and 2 were tested in the first quarter of 2013, the first at Site A and the second at Site B (Table 1). The firmware version on these samplers was not recorded, but was prior to version 3.03 (released in April 2012). These samplers were fully calibrated within 3 days of the testing conducted at the field sites and were not used for any other measurements before these tests were conducted. Each BHFS unit was bump tested at each field site prior to and after the field testing using 2.5% CH<sub>4</sub> in air and 100% CH<sub>4</sub>.

Follow-up testing was then conducted in March 2014. During this program, samplers 3, 4, and 5 were each tested under a variety of different conditions (Table 1) at sites C, D, and E with different NG compositions (Table 2). Sampler 3 had firmware version 3.04 (September 2013); this sampler was calibrated 2 weeks prior to the field test and had been used for emission measurements at production sites since that time. Samplers 4 and 5 had firmware version 3.03 (April 2012); these two samplers were calibrated each day before beginning field tests. Bump testing was also conducted on all of these instruments prior to the start of these follow-up tests.

The sample flow rate measurement (which in the BHFS is calculated from the pressure drop across an orifice plate) might be affected by as much as 20% by variations in NG densities at our test sites compared to CH<sub>4</sub>. We have eliminated this variability in our analysis by directly comparing the NG sample concentration indicated by the BHFS sensor to the external measurement by the Gas Sentry as opposed to comparing emission rates reported by the BHFS to the emission rates metered into the sampler.

### Results and Discussion

Evidence for sensor transition failure

Our initial tests with sampler 1 at site A and sampler 2 at site B showed that the internal sample stream sensor could not accurately measure concentrations that exceeded 6% NG in air

Table 1. Sun	Table 1. Summary of sampler testing	der testing	4° mer			1. 2
Sampler ID	Site	Firmware	Calibration status	Number of tests	Sensor transition failure rate	Comments
BHFS 1	A	Prior to V. 3.03	Within 3 days of	27	25 (92.6%)	Lab testing with 99.9% CH <sub>4</sub> showed no sensor transition failures.
BHFS 2	м	Prior to V. 3.03	Within 3 days of testing	9	4 (66.6%)	One test showed BHFS sensor response 5 times too low compared to the external sensor. This was not counted as failure since the BHFS apparently transitioned into the thermal conductivity
BHFS 3	C, D, E	V. 3.04	Two weeks prior to testing, then after failure occurred	8 prior to calibration; 5 after	2 (25%) prior to calibration; 0 after calibration	Sensor transition failure occurred after six tests in 20 minutes, Only two tests were conducted before the instrument was recalibrated after the failure appeared, both of which showed failure.
BHFS 4	C, D, E	V.3.03	Immediately prior to	10	0	
BHFS 5	C, D, E	V.3.03	Immediately prior to testing	15.	0	

Table 2. Well head gas composition at test sites (volume %)

Gas component	Site A, Permian Basin	Site B, Barnett Shale	Site C, Eagle Ford	Site D, Eagle Ford	Site E, Eagle Ford
Methane	66.26	77:81	90.81	80.81	76.98
Ethane	13.66	10.82	0.25	11.94	13.10
Propane	- 10.29	5.02	0.03	3.23	4.95
Carbon dioxide	0.34	2.26	8.76	2.02	2.37
n-Butane	3.76	1.40	0.00	0.56	0.30
Nitrogen	2.23	1.20	0.11	0.19	0.53
i-Butane	0.98	0.44	0.00	0.56	0.15
n-Pentane	0.87	0.38	0.00	0.14	0.07
Hexane	0.75	0.38	0.05	0.19	0.10
i-Pentane	0.83	0.30	0.00	0.17	0.19
Hydrogen sulfide	0.00	0:00	0.00	0.004	0.03

with wellhead gas compositions of 66.3% and 77.8% CH<sub>4</sub> (Figure 1 and Table 1). Above 6% NG, both samplers 1 and 2 indicated NG concentrations that rose and fell continuously between 1.1% and 5.9%, even though the actual sample concentrations ranged from 7% to 73% NG in air (Figure 1). Since the instrument is expected to transition from the catalytic oxidation sensor to the thermal conductivity sensor above approximately 5% NG, we concluded that the instruments were not properly transitioning between sensors. After this behavior was observed, the samplers were restarted, but the problem persisted. However, sampler 1 performed normally with commercial purity (>99.9%) CH<sub>4</sub> (Figure 1).

Further testing showed that the sensor transition failure problem also occurred in sampler 3, which had firmware version 3.04 (Figure 2). As seen in Figure 2, sensor transition failure for this sampler occurred in two test runs at site C (90.8% CH<sub>4</sub>). In this case, after sensor transition failure occurred, this sampler was calibrated (not simply bump tested) and this eliminated any further sensor transition failures that day. This sampler was calibrated prior to use the following day and performed correctly at sites D and E (data not shown), with high concentrations of heavier hydrocarbons (Table 2).

Samplers 4 and 5, which had firmware version 3.03 and were calibrated (again, not simply bump tested) each day before the

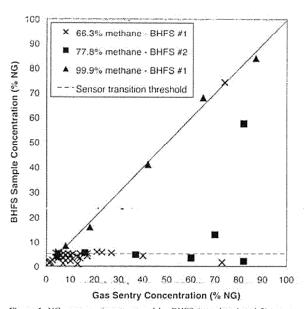


Figure 1. NG concentrations measured by BHFS (samplers 1 and 2) versus concentrations via the external Gas Sentry for natural gas with varying content of CH<sub>4</sub>. The dashed line indicates 5% sample concentration threshold, or the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity.

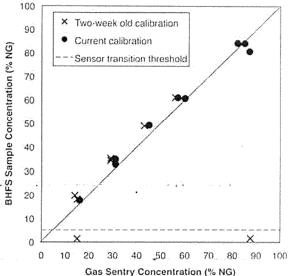


Figure 2. NG concentrations measured by BHFS (sampler 3) versus concentrations via the external Gas Sentry for natural gas at site C, 90.8% CH<sub>4</sub>. The dashed line indicates 5% sample concentration threshold, or the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity.

testing was conducted, did not show any evidence of sensor transition failure during testing at sites C, D, and E (data not shown).

We have shown that NG concentrations reported by the BHFS can be more than an order of magnitude too low, likely because the sampler does not properly transition between sensors, even at sites with CH<sub>4</sub> concentrations as high as 90.8%. Since the sample concentration is used to calculate emission rates, these errors would directly translate into reporting of erroneously low emission rates. This problem may be prevented with installation of the proper firmware, as sensor transition failure was not observed with firmware version 3.03, but it was observed with earlier versions and 3.04, and/or with more frequent calibration, as midday calibration of sampler 3 appeared to prevent further incidents of sensor transition failure during that sampling day (Figures 1 and 2). We have also shown that sensor transition failure can occur even with updated firmware if the calibration is as much as 2 weeks old (even though that is within the manufacturer's guidelines), again at sites with CH<sub>4</sub> concentrations as high as 91% (Figure 2). Further testing is needed on these instruments to determine the exact cause of these anomalously low measurements, and future work would benefit from more systematic testing of the impact of time since calibration, firmware version, and NG composition on performance of the BHFS sensors. Acknowledging this uncertainty, however, it is clear that this problem may lead to reporting of erroneously low CH<sub>4</sub> leak rates.

### Response factor versus sensor transition failure

We also performed tests of the response factor of the thermal conductivity sensor, or the indicated response of the instrument compared to the actual concentration of NG. The response factor of the Bacharach sensor to NG was recorded at sites A and C. At site A, the sensor indicated an NG concentration of 74% for 100% gas (with CH<sub>4</sub> and C<sub>2</sub>H<sub>6</sub> concentrations of 66.3% and 13.7%, respectively) and at site C, the sensor indicated 87.5% for 100% gas (with CH<sub>4</sub> and C<sub>2</sub>H<sub>6</sub> concentrations of 90.8% and 0.25%, respectively) (Table 1). For tests during which the BHFS transitioned to the thermal conductivity scale, the ratio of the BHFS sample concentrations to the exhaust sample concentrations measured by the external Bascom Turner Gas Sentry unit was  $1.014 \pm 0.035$  (using a 95% confidence limit). The response of the thermal conductivity sensor for both the BHFS and the Gas Sentry is similar and decreases with increasing heavier hydrocarbon concentrations. This is expected since the thermal conductivities of the heavier hydrocarbons are less than that of CH<sub>4</sub> (ranging from 61% for C<sub>2</sub>H<sub>6</sub> and 48% for butane compared to CH4, National Institute of Standards and Technology [NIST], 2011). It is interesting to note that correcting the sensor response based only on thermal conductivity and gas composition would still result in readings that would be 5% to 15% too low depending on gas composition, so empirical response factors based on actual instrument response appear to be the most accurate method to correct for response factor. However, our tests show that the issues described in Figures 1 and 2 are distinct from a response factor issue, as the errors in these tests were of a much larger magnitude than could be explained by response factor alone. Decreases in response due to gas composition were small compared to the magnitude of the sensor transition failure, and

this factor was eliminated in our field tests (Figures 1 and 2) by comparing the BHFS results to that of the Gas Sentry, which has a very similar response factor.

At least one previous study has observed erroneously low emission rates using the BHFS and attributed these errors to response factor issues, noting that the BHFS does not provide accurate results when surveying NMHC-rich gas streams (<95% CH<sub>4</sub>) (Modrak et al., 2012). These measurements were made at 23 production sites, including condensate tanks, pressure relief devices, produced water tanks, pneumatic devices, and connectors. Additionally, Modrak et al. (2012) collected canister samples from the sampler exhaust and found that the sample concentrations measured by the BHFS could be significantly lower than the actual concentrations (measured by GC-FID) when heavier hydrocarbons were present. Modrak et al. (2012) used the canister results to recalculate emission rates from the BHFS and found that the BHFS could underreport the actual emission rate by as much as two orders of magnitude for sources such as condensate tanks, and that errors increased with increasing heavier hydrocarbon concentrations, attributed to response factor issues.

Our reanalysis of the data presented in Modrak et al. (2012) indicates this issue may have been caused by sensor transition failure, and not response factor (Figure 3). For the seven cases where that study provided both the BHFS emission rate and the net difference between that emission rate and the one they calculated using canister data, we have calculated the BHFS sample concentration by assuming a sample flow rate of 8 scfm, which is the average flow rate used by the instrument (Bacharach, 2010). As shown in Figure 3, this calculation indicates that the BHFS underestimated the actual NG concentration as measured by canister sample between 5 and 320 times, respectively (Figure 3). All of the BHFS concentration measurements fall in the catalytic oxidation sensor range, even though the canister measurements indicated that there were numerous sample concentrations between 5% and 50%, which should have initiated a transition to the thermal conductivity sensor (Figure 3). This would explain why the errors they observed were orders of magnitude too low as opposed to response factor changes that might cause underreporting by up to a factor of 2. We note that since the work conducted by Modrak et al. (2012) was done in July 2011, the sampler used in that program would have had a firmware version earlier than

### Implications: Fort Worth Air Quality Study

The City of Fort Worth Natural Gas Air Quality Study also collected canister samples from the exhaust of the BHFS during measurements at NG production sites made in 2010 and 2011 (City of Fort Worth, 2011). During this work, more than 2100 measurements were made using the BHFS at 388 sites; canister samples were collected from the sampler exhaust for 164 of those measurements. Figure 4 presents the sample concentration indicated by the BHFS as a function of CH<sub>4</sub> concentration measured by canister sampling of the exhaust and subsequent analysis by gas chromatography—thermal conductivity detector (GC-TCD).

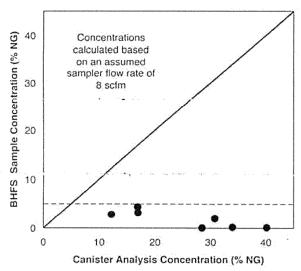


Figure 3. NG concentrations measured by the BHFS (calculated using an assumed BHFS flow rate of 8 scfm) versus concentrations via GC-FID ("actual sample concentration"). The dashed line indicates 5% sample concentration threshold, or the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity. Data are from Modrak et al. (2012).

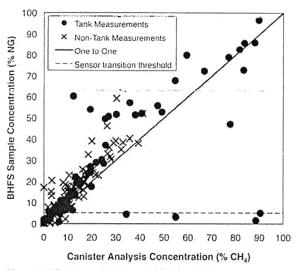


Figure 4. NG concentrations measured by the BHFS versus sample CH<sub>4</sub> concentrations via canister sampling with subsequent GC-TCD. The black line indicates where concentrations from both methods coincide. The dashed line indicates 5% sample concentration threshold, or the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity. Data are from City of Fort Worth Natural Gas Air Quality Study (City of Fort Worth, 2011).

As discussed previously, the BHFS sensors respond to other compounds in NG besides CH<sub>4</sub>, so it is expected that the indicated sample concentration would exceed the CH<sub>4</sub> concentration

measured in the canister, and that is the case for most of the comparisons in Figure 4. However, there were at least seven instances for which the sample concentration indicated by the BHFS was at or below 5% where the canister CH<sub>4</sub> concentration ranged from 6.1% to 90.4% (Figure 4). These occurrences are most likely due to sensor transition failure. Additionally, the calibration protocol for this study was to calibrate the sampler sensors at the start of the field campaign, and then bump test the sensors to check that the sensor response was within ±10% of the calibration gas value (City of Fort Worth, 2011), while our work has shown that more frequent recalibration may minimize the occurrence of sensor transition failure. As with Modrak et al. (2012), since this work was done in 2010 and 2011, the sampler used would not have had the update to firmware version 3.03.

The third factor that appears to affect sensor transition failure, the concentration of CH<sub>4</sub> in the wellhead gas, was not known for each measurement in the Fort Worth data set. However, previous work has shown that NG wells in Tarrant County, Texas (Fort Worth's county), have an average CH<sub>4</sub> content of 94.2% and a median content of 96.0% (Zumberge et al., 2012). The generally dry gas in this area may be a factor in the relatively low occurrence of sensor transition failure in this data set.

### Conclusions

We have shown that the BHFS instrument can make erroneously low estimates of NG emissions that may affect measurements made throughout the NG supply chain. We do not know exactly what conditions (firmware version, calibration interval, or concentration of CH<sub>4</sub> in the NG) may lead to sensor transition failure in the BHFS instrument, and there may be other variables that affect the instrument's performance, such as sensor age. Future work would benefit from systematic analysis of these factors to determine the best operating conditions for the BHFS. However, our preliminary work indicates that daily calibration and/or use of firmware version 3.03 may minimize the occurrence of sensor transition failure in the BHFS.

Sensor transition failure was observed in measurements at sites with CH<sub>4</sub> concentrations in the wellhead gas ranging from 66.3% to 90.8%. Consequently, this phenomenon may occur throughout the NG industry, not just at production and processing sites with higher concentrations of >C2 hydrocarbons, but also at transmission and distribution sites, even though CH<sub>4</sub> concentrations at those sites typically exceed 90%. One example would be measurements made under EPA Subpart W at transmission sites, where use of the high-flow sampler (of which the BHFS is the only commercially available model) is approved for reporting purposes (40 CFR 98.233). Occurrence of sensor transition failure would result in emission inventories being reported to that program as erroneously low. This phenomenon may also play a role in the discrepancy between top down and bottom up inventories, since it could result in low emissions factors used to scale CH<sub>4</sub> emissions from the ground level (Miller et al., 2013; Brandt et al., 2014). Because regulation of CH<sub>4</sub> leaks from NG production and distribution systems is imminent, and because these leaks may create hazardous conditions along the NG supply chain, it is essential that proper methodology is employed for leak rate measurements.

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### About the Authors

Touché Howard is a chemical engineer in Durham, NC, and the developer of the high-volume sampler.

Thomas W. Ferrara is the manager of the Conestoga Rovers & Associates, Inc., source measurement group in Niagara Falls, NY.

Amy Townsend-Small is an assistant professor of goology at the University of Cincinnati in Cincinnati, OH.

### **Energy Science & Engineering**



RESEARCH ARTICLE

### University of Texas study underestimates national methane emissions at natural gas production sites due to instrument sensor failure

Touché Howard

Indaco Air Quality Services, Inc., Durham, North Carolina

### Keywords

Greenhouse gases, methane, natural gas

### Correspondence

Touche Howard, Indaco Air Quality Services, Inc., Durham, NC, Tel. (919), 943, 9406, E-mail: touche.howard@indacoags.com

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### Abstract

The University of Texas reported on a campaign to measure methane (CH<sub>4</sub>) emissions from United States natural gas (NG) production sites as part of an improved national inventory. Unfortunately, their study appears to have systematically underestimated emissions. They used the Bacharach Hi-Flow Sampler (BHFS) which in previous studies has been shown to exhibit sensor failures leading to underreporting of NG emissions. The data reported by the University of Texas study suggest their measurements exhibit this sensor failure, as shown by the paucity of high-emitting observations when the wellhead gas composition was less than 91% CH4, where sensor failures are most likely; during follow-up testing, the BHFS used in that study indeed exhibited sensor failure consistent with under-reporting of these high emitters. Tracer ratio measurements made by the University of Texas at a subset of sites with low CHa content further indicate that the BHFS measurements at these sites were too low by factors of three to five. Over 98% of the CH<sub>4</sub> inventory calculated from their own data and 41% of their compiled national inventory may be affected by this measurement failure. Their data also indicate that this sensor failure could occur at NG compositions as high as 97% CH4, possibly affecting other BHFS measurement programs throughout the entire NG supply chain, including at transmission sites where the BHFS is used to report greenhouse gas emissions to the United States Environmental Protection Agency Greenhouse Gas Reporting Program (USEPA GHGRP, U.S. 40 CFR Part 98, Subpart W). The presence of such an obvious problem in this high profile, landmark study highlights the need for increased quality assurance in all greenhouse gas measurement programs.

### Introduction

The climatic benefits of switching from coal to natural gas (NG) depend on the magnitude of fugitive emissions of methane (CH<sub>4</sub>) from NG production, processing, transmission, and distribution [12, 13, 27]. This is of particular concern as the United States increasingly exploits NG from shale formations: a sudden increase in CH<sub>4</sub> emissions due to increased NG production could trigger climate "tipping points" due to the high short-term global warming potential of CH<sub>4</sub> (86× carbon dioxide on a 20-year time scale) [19]. The United States Environmental

Protection Agency (USEPA) estimates CH<sub>4</sub> emissions from the NG supply chain by scaling up individual ground-level measurements, mostly collected by reporting from industry [26]. However, some recent studies have questioned whether these "bottom-up" inventories are too low, since airborne measurements indicate that CH<sub>4</sub> emissions from NG production regions are higher than the inventories indicate [5, 14, 17, 20, 21].

In order to help determine the climate, consequences of expanded NG production and use, and to address the apparent discrepancy in top-down and bottom-up measurements, the University of Texas (UT) at Austin and the

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Environmental Defense Fund launched a large campaign to measure CH4 emissions at NG production sites in the United States [1]. This study used both existing EPA GHG inventory data and new measurements to compile a new national inventory of CH<sub>4</sub> emissions from production sites. Forty-one percent of this new inventory was based on measurements made by [1], which included measurements of emissions from well completion flowbacks as well as measurements of emissions from chemical injection pumps, pneumatic devices, equipment leaks, and tanks at 150 NG production sites around the United States already in routine operation (measurements from tanks were not used for inventory purposes). However, the measurements of emissions at well production sites already in operation (which comprised 98% of the new inventory developed by [1]) were made using the Bacharach Hi-Flow Sampler (BHFS; Bacharach, Inc., New Kensington, PA) and recent work has shown that the BHFS can underreport individual emissions measurements by two orders of magnitude [10]. This anomaly occurs due to sensor transition failure that can prevent the sampler from properly measuring NG emission rates greater than ~0.4 standard cubic feet per minute (scfm; 1 scfm = 1.70 m<sup>3</sup> h<sup>-1</sup> or 19.2 g min<sup>-1</sup> for pure CH<sub>a</sub> at 60°F [15.6°C] and 1 atm; these are the standard temperature and pressure used by the U.S. NG industry). Although this failure is not well understood, it does not seem to occur when measuring pure CH, streams, but has been observed in four different samplers when measuring NG streams with CH<sub>4</sub> contents ranging from 66% to 95%. The sampler's firmware version and elapsed time since last calibration may also influence the occurrence of this problem [10, 18].

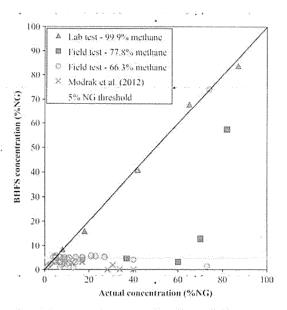
This paper presents an analysis of the UT [1] emissions measurements that were made with the BHFS, and shows that high emitters (>0.4 scfm [0.7 m³ h⁻¹]) were reported very rarely at sites with a low CH<sub>4</sub> content in the well-head gas (<91%), consistent with sensor transition failure. It also details testing of the exact BHFS instrument used in that study and shows the occurrence of this sensor failure at an NG production site with a wellhead composition of 91% CH<sub>4</sub> (the highest CH<sub>4</sub> concentration site available during testing). Finally, the downwind tracer ratio measurements made by [1] at a subset of their test sites are reexamined and indicate that the BHFS measurements made at sites with low wellhead CH<sub>4</sub> concentrations were too low by factors of three to five.

### Evidence of BHFS Sensor Transition Failure in the UT Dataset

The Allen et al. [1] UT dataset is unique due to the large number of BHFS measurements made across a wide geographic range, the variety of emissions sources

(equipment leaks, pneumatic devices, chemical injection pumps, and tanks) and the wide range of NG compositions (67.4–98.4% CH<sub>4</sub>) that were sampled. As such, the UT study provides an important opportunity to evaluate the occurrence of sensor transition failure in the BHFS as well as the impact of this issue on emission rates and emissions factors based on measurements in other segments of the NG supply chain.

The BHFS uses a high flow rate of air and a loose enclosure to completely capture the NG-emitting from a source, with the emission rate calculated from the total flow rate of air and the resulting sample NG concentration, after the background NG concentration is subtracted. The sampler uses a catalytic oxidation sensor to measure sample concentrations from 0% to 5% NG in air, but must transition to a thermal conductivity sensor in order to accurately measure sample concentrations higher than 5%. It is the failure of the sampler to transition to the higher range that has been previously observed by Howard et al. [10] and which can prevent the sampler from correctly measuring emission rates larger than 0.3–0.5 scfm (0.5–0.9 m³ h<sup>-1</sup>) (corresponding to sampler flow rates of 6–10 scfm [10–17 m³ h<sup>-1</sup>]). Figure 1 summarizes data

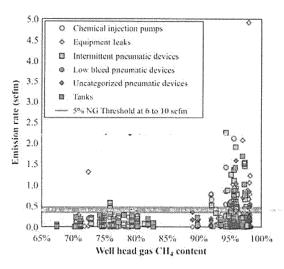


**Figure 1.** Occurrence of sensor transition failure in BHFS instruments with natural gas of varying CH<sub>4</sub> content from field and lab testing and from emission measurement studies (data from [10, 18]). NG concentrations in the BHFS sampling system measured by the BHFS internal sensor are compared to independent measurements of the sample NG concentrations. The 5% NG sample concentration threshold is the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity. BHFS, Bacharach Hi-Flow Sampler; NG, natural gas.

showing the occurrence of sensor transition failure in several BHFS instruments during both field and laboratory testing as well as an example of the failure that occurred during an emission measurement study [10, 18].

Figure 2 presents the BHFS emission measurements from [1] as a function of percent CH<sub>4</sub> in wellhead gas at each site. Figure 2 also shows a line corresponding to emission rates of 0.3–0.5 scfm (0.5–0.9 m³ h<sup>-1</sup>), which represents the range of emission rates that would require transition from the catalytic oxidation sensor to the thermal conductivity sensor at sample flows ranging from 6 to 10 scfm (10–17 m³ h<sup>-1</sup>).

As seen in Figure 2, there are very few measurements in the thermal conductivity sensor range (above ~0.4 scfm [0.7 m³ h<sup>-1</sup>]) at sites where the wellhead gas composition of CH<sub>4</sub> is less than 91%, and this is true across all source categories. Raw data for sample flow and concentration from the BHFS were not provided in [1] supplemental information, so for this analysis, an average BHFS sample flow rate of 8 scfm (14 m³ h<sup>-1</sup>) has been assumed, which is the lower of the two sampling flows specified by the Bacharach operating manual [4]. At this sample flow rate, an emission source of 0.4 scfm (0.7 m³ h<sup>-1</sup>) corresponds with a sample concentration of 5% NG in air, above



**Figure 2.** Emission rates of various sources measured by BHFS at NG production sites versus CH<sub>4</sub> concentration of the wellhead gas (data from [1]). The solid line indicates the maximum emission rate that could be measured by the catalytic oxidation sensor only (i.e., in the case of sensor transition failure). For sites with a NG composition greater than 91% CH<sub>4</sub>, 13.3% of the measurements are in the TCD sensor range, assuming a sampler flow rate of 8 cubic feet per minute. For sites with less than 91% CH<sub>4</sub>, only 1.5% of the measurements are in the TCD range. BHFS, Bacharach Hi-Flow Sampler; NG, natural gas; TCD, thermal conductivity detector.

which point the sampler would need to transition to the thermal conductivity sensor to allow for accurate measurements. For sites with CH<sub>4</sub> concentrations less than 91%, only four out of 259 measurements (1.5%) exceeded 0.4 scfm (0.7 m3 h-1), while for sites with CH4 concentrations greater than 91%, 68 out of 510 measurements (13.3%) exceeded 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>). Consequently, there were almost nine times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH<sub>4</sub> (Fig. 2). If the sample flow rate were 6 scfm (10 m3 h-1) (due to a flow restriction or reduced battery power), the threshold for transition to the thermal conductivity range would be 0.3 scfm (0.5 m<sup>3</sup> h<sup>-1</sup>); this would still mean that there were almost seven times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH4 than at sites with >9.1% CH4. Although it is well known that a small percentage of NG emission sources account for most of the total emissions from any given population [9, 15, 25], it is unlikely that almost all the significant emitters at NG production sites would occur only at sites with well head gas compositions >91% CH... It is also unlikely that the emission rates of all of the source categories surveyed by [1], which had diverse emission mechanisms such as equipment leaks, pneumatic controllers, chemical injection pumps, and tanks, would all have a ceiling of ~0.4 scfm (0.7 m3 h-1) at sites with lower wellhead gas CH4 concentrations. Consequently, the low occurrence of high emitters at sites with lower wellhead gas CH, concentrations in [1] indicates that sensor transition failure occurred at sites with CH<sub>3</sub> content <91% and is consistent with the BHFS sensor failure found by Howard et al. [10].

### Alternative Theories for the Emission Rate Pattern

Other possible causes of the emission rate pattern in the UT BHFS measurements were considered, including: regional operating differences at production sites; lighter gas densities resulting in higher emission rates; and improved detection of emissions by auditory, visual, and olfactory (AVO, e.g., [24]) methods at sites with heavier hydrocarbon concentrations.

### Regional operating differences

Allen et al. [1] point out that air pollution regulations in Colorado which required installation of low bleed pneumatic devices in ozone nonattainment areas after 2009 might have led to lower emission rates in the Rocky Mountain region, which also had the lowest average concentration of CH<sub>4</sub> in the wellhead gas. However, if the

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Rocky Mountain region is removed from the analysis, the occurrence of emitters >0.4 scfm (0.7 m³ h⁻¹) at sites with wellhead gas <91% CH4 was still only four out of 129 measurements (3.1%), while for sites with CH4 concentrations greater than 91%, there remain 68 out of 510 measurements (13.3%) that exceeded 0.4 scfm (0.7 m³ h⁻¹) (there were no Rocky Mountain sites with CH4 >91%). Consequently, even if the Rocky Mountain region is removed from consideration, the occurrence of emitters >0.4 scfm (0.7 m³ h⁻¹) was almost four times less at sites with less than 91% CH4 than at sites with greater than 91% CH4, so air quality regulations in Colorado do not appear to be the cause of the emission rate trend shown in Figure 2.

Beyond air pollution regulations, other unknown regional operating practices unrelated to CH<sub>4</sub> concentration might coincidentally cause the apparent relationship of site CH<sub>4</sub> concentrations with the occurrence of high emitters. However, as shown in Figure 3, the increase in leaks >0.4 scfm (0.7 m³ h<sup>-1</sup>) directly correlates with the increase in the average regional CH<sub>4</sub> concentration. Because there are four regions and two variables (site CH<sub>4</sub> concentration and the percent of leaks >0.4 scfm [0.7 m³ h<sup>-1</sup>]), the likelihood that regional operating characteristics would coincidentally cause the increase in occurrence of leaks >0.4 scfm (0.7 m³ h<sup>-1</sup>) to mirror the increasing regional site CH<sub>4</sub> concentration is only one in 24 (four factorial), or ~4%.

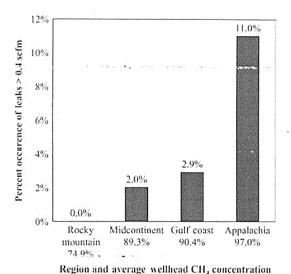


Figure 3. Occurrence of equipment leaks >0.4 scfm in each region of the [1] equipment leak data set. The odds of the occurrence of leaks

the [1] equipment leak data set. The odds of the occurrence of leaks >0.4 scfm being positively correlated with site CH<sub>4</sub> concentration are one in 24, which makes it unlikely this trend is due to regional operating effects.

Other known operating characteristics of the regions, such as average site pressure and average site age, are not related to the occurrence of equipment leaks >0.4 scfm (0.7 m³ h<sup>-1</sup>); average site pressures show no correlation, and average site age is negatively correlated with the occurrence of equipment leaks >0.4 scfm (0.7 m³ h<sup>-1</sup>).

Another argument against regional differences comes from the air quality study conducted by the City of Fort Worth ([6]; or the Ft. Worth study). Ft. Worth is part of the Mid-Continent region defined by [1], where the occurrence of equipment leaks only (as opposed to all BHFS measurement categories) >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) observed by [1] was 2.0% of the total equipment leaks in that region. However, equipment leaks >0.4 scfm  $(0.7\ m^3\ h^{-1})$  were 9.9% of the equipment leaks measured in the Ft. Worth study. This was determined using the Ft. Worth study categories of valves and connectors; their remaining category of "other", which included pneumatic control devices, had an even higher occurrence of sources >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) of 27.0%. Previous work [10] has shown that although sensor transition failure likely occurred in the Ft. Worth study, these incidents were limited compared to those in [1]. Consequently, the much lower occurrence of leaks >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) in the Mid-Continent region in [1] compared to the Ft. Worth study indicates that sensor transition failure was responsible for the low occurrence of emitters <0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) as opposed to regional differences.

### Gas density

Wellhead gas with a lower  $\mathrm{CH_4}$  and a greater heavier hydrocarbon content will be denser than gas with higher  $\mathrm{CH_4}$  content. Since gas flow through an opening is inversely related to the square root of the gas density, streams with lower  $\mathrm{CH_4}$  content would have a lower flow rate if all other conditions were the same. However, this would cause at most a 20% decrease for the lowest  $\mathrm{CH_4}$ /highest heavier hydrocarbon streams compared to the highest  $\mathrm{CH_4}$ /lowest heavier hydrocarbon streams observed in the UT study. This would also result in a gradual increase in emissions as  $\mathrm{CH_4}$  content increased, as opposed to the dramatic increase in emissions observed over a very narrow range of  $\mathrm{CH_4}$  concentrations (Fig. 2).

### **AVO** detection

AVO methods might improve for gas streams with a greater proportion of heavier hydrocarbons, since those streams would have greater odor and might leave more visible residue near a leak. However, Figure 4 presents the occurrence of emitters >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) as a function of site CH<sub>4</sub> concentrations in the Appalachia

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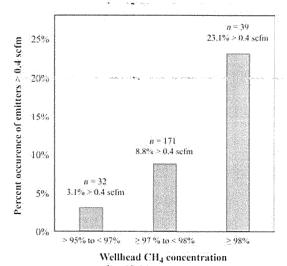


Figure 4. Occurrence of emitters >0.4 scfm as a function of site wellhead gas composition in [1] for the Appalachia region. An emission rate of greater than 0.4 scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of 8 scfm. The dramatic increase in emitters >0.4 scfm oven a narrow concentration-range argues against the possibility that auditory, visual, and olfactory leak detection is the cause of the emission rate pattern seen in the [1] data set.

region alone. This region had the highest average CH, concentration in wellhead gas of any of the regions sampled in [1]. As seen in Figure 4, even over a very narrow range of site CH<sub>4</sub> concentrations (from 95% to >98% CH<sub>4</sub>), there is a dramatic increase in emitters >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) with increasing CH<sub>4</sub> concentration. It is unlikely that AVO methods would become so much more efficient over such a narrow range of high CH<sub>4</sub> concentrations where the gas streams are likely odorless and would leave little residue. This dramatic increase in high emitters at sites with high CH<sub>4</sub> concentrations within the Appalachia region alone also argues against the previously discussed regional operating differences hypothesis in general, since this trend is within a single region. Additionally, although the Rocky Mountain region surveyed by UT [1] had the lowest average site CH<sub>4</sub> concentration (74.9%) and heaviest hydrocarbon content, it actually had the highest number of equipment leaks (of any size) per well of all the regions, and there were 25% more leaks per well in that region than in the Appalachia region, which had the highest average site CH<sub>4</sub> concentration (97.0%) and therefore the lowest heavier hydrocarbon content. If AVO methods were more effective due to the presence of heavier hydrocarbons, it seems unlikely the region with the heaviest hydrocarbon concentrations would have the highest rate of overall leak occurrences.

### Field Testing of the UT BHFS

Because the trend in the [1] data was consistent with sensor transition failure in the BHFS and no other explanation seemed plausible, I partnered with UT to test the sampler used by [1]. During that field program, the UT sampler had a version of firmware earlier than version 3.03, and older firmware versions have been shown to exhibit sensor transition failure [10]. However, the possible effect of the sampler's firmware version on the sensor failure was not known before this testing of the UT sampler, and at the time of my testing its firmware had been upgraded to a custom version (3.04).

As previously explained, the BHFS uses a catalytic oxidation sensor to measure sample stream concentrations from 0% to ~5% NG, and a thermal conductivity sensor for concentrations from ~5% to 100% NG. The catalytic oxidation sensor is typically calibrated with 2.5% CH<sub>4</sub> in air and the thermal conductivity sensor is calibrated with 100% CH<sub>4</sub> [4]. The manufacturer recommends sensor calibration every 30 days, a process which adjusts the response of the instrument. The calibration may also be checked ("bump-tested") periodically by the user, which does not adjust the instrument response. It is important to note that the description of the BHFS sensor operation in the supplemental information of [1] is incorrect, as they state that:

[A] portion of the sample is drawn from the manifold and directed to a combustibles sensor that measures the sample's methane concentration in the range of 0.05–100% gas by volume. The combustibles sensor consists of a catalytic oxidizer, designed to convert all sampled hydrocarbons to CO<sub>2</sub> and water. A thermal conductivity sensor is then used to determine CO<sub>2</sub> concentration.

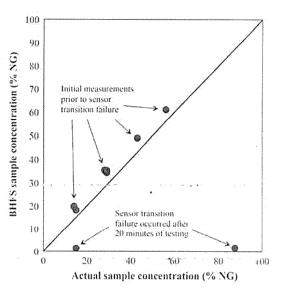
However, the BHFS manual [4] clearly states that the catalytic oxidation sensor is used to measure concentrations from 0% to 5% CH<sub>4</sub> and the thermal conductivity sensor from 5% to 100% CH<sub>4</sub>. This is a critical distinction because understanding that the BHFS uses a different sensor for each range and that it must transition from the catalytic oxidation sensor to the thermal conductivity sensor in order to conduct accurate measurements is critical to understanding the problem of sensor transition failure.

I initially conducted field testing of the UT sampler in conjunction with the UT team at a NG production site with a wellhead gas CH<sub>4</sub> concentration of 90.8%. NG composition analysis (via gas chromatograph-flame ionization detector) of wellhead gas at this site was conducted by the host company just prior to the sampler testing. The tests were conducted by metering known flow rates of NG into the BHFS inlets through a rotameter (King Instrument Company, Garden Grove, CA; 0–10 scfm air

scale). The sample concentration indicated by the internal BHFS sensor was recorded and compared to an external gas concentration monitor used to measure the actual NG concentration at the sampler exhaust (Bascom-Turner Gas Sentry CGA 201, Norwood, MA). The Gas Sentry unit was calibrated with 2.5% and 100% CH<sub>4</sub> prior to the testing; exhaust concentrations measured using this unit agreed with concentrations calculated using the sampler flow rate and amount of NG metered into the inlet to within an average of ±6%.

This field testing was conducted in March of 2014 and is described by [10]; the UT sampler is identified therein as BHFS No. 3. At the time of this testing, the UT BHFS had firmware Version 3.04 (September 2013); this sampler had been calibrated 2 weeks prior to the field test and had been used for emission measurements at production sites since that time. The response of the sensors was checked ("bump-tested") by the UT field team but not calibrated prior to the start of testing. This was apparently consistent with the UT field program methodology: the sampler had been used for measurements with only sensor bump tests, but without the actual calibration unless the sensors failed the bump tests (as was acceptable according to the manufacturer's guidelines) during their ongoing field measurement program and was provided to me for these measurements "ready for testing".

Although the UT sampler's internal sensors initially measured the sample concentration correctly, after ~20 min of testing the sampler's sensors failed to transition from the catalytic oxidation scale (<5% NG) to the thermal conductivity scale (>5% NG), resulting in sample concentration measurements that were 11-57 times lower than the actual sample concentration (Fig. 5). Because sample concentration is directly used to calculate emission measurements made by the sampler, this would result in emission measurements that are too low. After this sensor transition failure occurred, the UT BHFS was calibrated (not simply "bump-tested") and thereafter did not exhibit any further sensor transition failures even during a second day of testing at sites with wellhead CH<sub>4</sub> concentrations as low as 77%. Two other BHFS that were not part of the UT program were also tested using the same procedure; these instruments had the most updated firmware commercially available (Version 3.03) and were put through an actual calibration sequence by the instrument distributor's representative prior to any testing. Neither of these instruments exhibited sensor transition failure at any of the sites. These results combined with the sensor transition failure previously observed in instruments with earlier versions of firmware suggest that the combination of updated firmware and frequent actual calibrations might reduce sensor failure, although this has not been proved conclusively [10, 11].



**Figure 5.** Performance of the BHFS used during the [1] study with NG composed of 90.8% CH<sub>4</sub>; instrument firmware had been upgraded to version 3.04 after that study but before this testing; calibration was 2 weeks old. Sensor transition failure set in after ~20 min of testing; this failure was eliminated once the BHFS was put through a calibration sequence (as opposed to just a response test). BHFS, Bacharach Hi-Flow Sampler; NG, natural gas.

The UT recently published a follow-up study of pneumatic device emissions [2]. As part of this work, Allen et al. [2] conducted laboratory testing of the UT BHFS by making controlled releases of both 100% CH<sub>4</sub> and a test gas of 70.5% CH<sub>4</sub> mixed with heavier hydrocarbons into the UT BHFS and did not report any sensor transition failures during these tests, but during this laboratory testing the sampler (with the updated firmware version 3.04) was calibrated (not 'bump-tested") immediately prior to any testing. Consequently, the absence of sensor failure during their laboratory testing is consistent with the results observed during the March 2014 field tests, where calibrating the instrument eliminated the sensor failure.

Allen et al. [3] have suggested that the protocol during their field campaign was to check the calibration of the UT BHFS anytime it was turned on and that not following this protocol led to the sensor transition failure observed during this testing. However, in this instance, the sensor failure occurred both prior to and after the instrument was restarted. Additionally, the UT team observing the testing process did not suggest a calibration check when the instrument was turned back on for further testing. It was only after the sensor failure was observed that they checked and calibrated the instrument, so it

does not appear that their protocol was to check the instrument calibration anytime it was turned on.

In summary, because the firmware for the UT sampler was updated prior to this testing (and therefore not the same as the version used-during the UT field campaign [1]), and updated firmware may be a factor in reducing sensor failure, it is not expected that these test results are representative of how frequently sensor transition failure might have occurred during the UT study [1]. However, these results do clearly demonstrate that sensor transition failure could occur while using the UT BHFS.

### Comparison With Other Pneumatic Device Studies

Two other recent studies have measured emission rates from pneumatic devices by installing meters into the supply gas lines of the devices, as opposed to measuring emissions using the BHFS as was done by Allen et al. [1]. Prasino [22] used the meter installation technique to study emissions from pneumatic controllers in British Columbia, and the UT follow-up study [2] installed meters to measure emission rates from pneumatics in the four regions surveyed in the previous UT study [1].

Unfortunately, it is not possible to compare the pneumatic device emission factors from [1] to those from either the Prasino study, or from [2], because even though [1] sought to randomly sample pneumatic devices, the result was clearly an emitter data set (measurements focused on pneumatic devices that were emitting), while the Prasino data set was made with a random selection of devices and [2] made comprehensive measurements of all devices that could be measured safely at each site. This difference can be demonstrated by comparing the percentage of emitting intermittent pneumatic devices occurring in [1] to that in [2]. In [1], 95.3% (123 out of 129 intermittent devices) were greater than zero, with the smallest nonzero emitter equal to 0.12 scfh (0.0034 m<sup>3</sup> h<sup>-1</sup>). In [2], only 57.5% (184 out of 320 intermittent devices) were greater than zero. This percentage of nonzero measurements drops further if the lowest nonzero emitter (0.12 scfh; 0.0034 m3 h-1) observed by [1] is used as a threshold, in which case only 21.3% (68 out of 320) would be considered emitters. Since this threshold of 0.12 scfh (0.0034 m<sup>3</sup> h<sup>-1</sup>) is 25 times lower than the typical minimum range of the Fox FT2A meters by [2], the reported emitters below this threshold are most likely instrument noise caused by the meter's thermal elements inducing convection currents [7].

Consequently, although the intent of [1] was to survey randomly selected devices, their approach actually resulted in a data set comprised almost exclusively of emitting devices; this possibility is acknowledged by [2]. Therefore, average emissions and emission factors for pneumatic devices calculated from [1] cannot be compared to those calculated from data collected by random or comprehensive sampling, such as presented in [22] or [2], because the emitter data set removes almost all the zero emitters and would result in much higher average emissions.

However, both [1] and [2] provide the CH<sub>4</sub> composition of the wellhead gas at the sites surveyed. This allows a comparison of emission rate patterns as a function of CH<sub>4</sub> concentration between devices measured by the BHFS [1] and by installed meters [2]. If the scarcity of high emitters measured by BHFS at sites with lower CH<sub>4</sub> concentrations in the initial UT study [1] was not an artifact caused by sensor transition failure, then the same concentration pattern should be present whether measured by the BHFS or by installed meters.

For this analysis, I removed the Rocky Mountain region to eliminate any bias from current or impending regulations that might have affected emission rates. Additionally, I focused on emissions from intermittent pneumatics because that provides the most complete data set from the two studies. Finally, as noted previously, the pneumatic device measurements from [1] apparently focused on emitting devices, whereas the devices surveyed in [2] were sampled as comprehensively as possible so the occurrences of high emitters in each study cannot be directly compared. Consequently, it is the ratio of the occurrences of high emitters at low CH<sub>4</sub> sites compared to high CH<sub>4</sub> sites-within each study that must be compared.

As seen in Table 1, when measured by [1] via BHFS, the occurrence of emitters >0.4 scfm (0.7 m³ h⁻¹) (on a percentage basis) at sites with wellhead gas compositions <91% CH<sub>4</sub> is almost a factor of five less than at sites with CH<sub>4</sub> >91%, consistent with BHFS sensor failure. Conversely, when measured via installed meters [2], the occurrence of emitters >0.4 scfm (0.7 m³ h⁻¹) at sites with wellhead gas compositions <91% CH<sub>4</sub> is almost a factor of three higher than at sites with >91% CH<sub>4</sub>, indicating a complete reversal in this trend. This stark difference between BHFS measurements and installed meter measurements corroborates that the scarcity of high emitters at sites with lower wellhead gas CH<sub>4</sub> content present in [1] was an artifact due to sensor failure in the BHFS.

### Focused Analysis of the UT Study Equipment Leaks

In order to better understand the threshold of weilhead gas CH<sub>4</sub> concentrations at which sensor transition failure might occur, I conducted further analysis focused only on the equipment leak measurements in [1]. Equipment leaks were targeted because they are expected to be short term, steady state measurements, whereas emissions

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**Table 1.** Occurrence of intermittent pneumatic device high emitters as a function of wellhead gas composition, measured by Bacharach Hi-Flow Sampler (BHFS) and installed meters (Rocky Mountain region excluded).

and the supplier of the suppli	No: of devices measured	No. of devices with emissions >0.4 scfm	<ul> <li>% of devices with emissions &gt;0.4 scfm</li> </ul>
Allen et al. [1] (Measured by BHFS sampler)			enen disabilita dida disabilita di alika esen dida dida da ada adi di kereka espirah da manana di Lama da Lama Sa
Wellhead gas composition >91% CH <sub>a</sub>	85	28	32.9
Wellhead gas composition <91% CH <sub>4</sub>	44	3	6.8
Ratio of frequency of high emitters at sites with wellhead wellhead gas compositions >91% CH <sub>4</sub>	gas compositions <91% CH <sub>2</sub>	to sites with	0.21
Allen et al. [2] (Measured by installed meters)			
Wellhead gas composition >91% CH <sub>a</sub>	106	3	2.8
Wellhead gas composition <91% CH <sub>A</sub>	97	8	8.2
Ratio of frequency of high emitters at sites with wellhead wellhead gas compositions >91% CH <sub>4</sub>	gas compositions <91% CH <sub>2</sub>	to sites with	2.9

reported from pneumatic devices and chemical injection pumps are likely to be an average of several measurements, and emissions from tanks may have an NG composition different from the reported wellhead composition.

Figure 6 presents the occurrence of equipment leaks in [1] that are >0.4 scfm (0.7 m $^3$ -h $^{-1}$ ) as a function—of site CH $_4$  concentrations. At sites with gas compositions of >97% CH $_4$ , 11.7% of the leaks were >0.4 scfm (0.7 m $^3$  h $^{-1}$ ). At sites with wellhead compositions between 90% and 97% CH $_4$ , only 2.7% of the leaks were >0.4 scfm

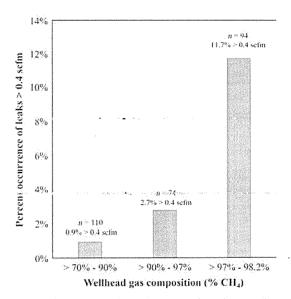


Figure 6. Occurrence of equipment leaks >0.4 scfm as a function of site well head gas  $CH_4$  content in the [1] study. Leaks >0.4 scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of 8 scfm. The large increase in the occurrence of leaks >0.4 scfm at sites with  $CH_4$  content >97% indicates sensor transition failure below that threshold.

(0.7 m³ h<sup>-1</sup>), and this occurrence dropped to less than 1% at sites with wellhead gas compositions of <90% CH<sub>4</sub>, indicating that the sampler's ability to measure leaks >0.4 scfm (0.7 m³ h<sup>-1</sup>) declined dramatically with decreasing concentrations of CH<sub>4</sub> in the wellhead gas (Fig. 6). This analysis indicates the BHFS may underreport emitters >0.4 scfm (0.7 m³ h<sup>-1</sup>) even when making measurements of NG streams with CH<sub>4</sub> content up to 97%, and provides a valuable refinement of the possible CH<sub>4</sub> concentration threshold where sensor failure may occur, since the highest CH<sub>4</sub> wellhead content available for direct field testing of the BHFS was only 91.8%.

### Comparison of the UT Study Downwind Tracer Ratio Measurements to On-Site Measurements

Allen et al. [1] also made emission measurements using a downwind tracer ratio method at 19 sites for comparison to their on-site measurements. Their emissions from onsite measurements were calculated by using direct measurements of equipment leaks and pneumatic devices that were made by the UT team combined with estimates of emissions from any sources at the well pad that were not measured. These unmeasured sources included all tanks and compressors (compressors were a small source in comparison to all other sources) as well as any pneumatics that was not directly measured during the site survey. For CH<sub>2</sub> emissions from tanks and compressors, the authors used "standard emissions estimation methods" [1]. For pneumatic devices that were not surveyed, they applied their own emission factors based on the measurements of pneumatic devices collected during the UT study.

The tracer ratio measurements were made by releasing a tracer gas at a known rate to simulate the emissions from the site being measured. Simultaneous downwind measurements were then made of the concentrations of both the tracer gas and CH<sub>4</sub>, and then the emission rate

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of  $\mathrm{CH_4}$  was calculated after correcting for background  $\mathrm{CH_4}$  and tracer concentrations. The tracer ratio method allows for the calculation of  $\mathrm{CH_4}$  emissions from the entire production site by accounting for the dilution of  $\mathrm{CH_4}$  as it is transported into the atmosphere from the source to the receptor.

In summarizing their tracer ratio measurements, [1] state: "For the production sites, emissions estimated based on the downwind measurements were also comparable to total on-site measurements; however, because the total on-site emissions were determined by using a combination of measurements and estimation methods, it is difficult to use downwind measurements to confirm the direct source measurements." However, upon further examination, I found that the downwind tracer measurements do in fact indicate the occurrence of sensor transition failure in their BHFS measurements.

Table 2 summarizes the characteristics of the sites surveyed by [1] using both the BHFS and the tracer ratio method. As described above, the on-site total is a combination of the measurements made by BHFS and estimates for any sources not actually measured by the UT team. I calculated the ratio of actual BHFS measurements to

the total reported on-site emissions (estimated and measured) using the supplemental information provided by [1]. Actual measured emissions ranged from 1% to 79% of the total reported on-site emissions and the on-site total emissions range from 13% to 3500% of the downwind tracer ratio measurements (Table 2).

Table 3 compares the tracer ratio measurements to the on-site emissions, categorized by  $\mathrm{CH_4}$  content in the well-head gas and by the fraction of actual BHFS measurements that comprise the on-site emissions. As shown in Table 3, when comparing all sites without separating them into these categories, the total of the tracer ratio measurements does agree closely to the on-site emissions, as [1] concluded. However, four of the sites had wellhead gas compositions of  $\geq\!97\%$   $\mathrm{CH_4}$ , at which the BHFS would be expected to make accurate measurements. The remaining 15 sites had wellhead gas compositions of  $<\!82\%$   $\mathrm{CH_4}$ , at which sensor transition failure might occur and the BHFS would underreport emissions measurements.

Once the sites are categorized by these wellhead gas compositions, a deficit between the on-site emissions and the tracer ratio measurements appears in sites with lower CH<sub>4</sub> concentrations, and this deficit becomes more

Table 2. Sites surveyed by Allen et al. [1] using both Bacharach Hi-Flow Sampler (BHFS) and downwind tracer methods.

	May something som	Wellhead gas CH <sub>a</sub> concentration (%)	On-site total <sup>2</sup> (BHFS measurements and estimates) (scfm CH <sub>4</sub> )	BHFS measure- ments/on-site total <sup>3</sup>	Leaks measured by BHFS/on-site total <sup>3</sup>	. Since the tip of the second second	
Tracer site	BHFS site					Tracer ratio emission rate (scfm CH <sub>d</sub> )	On-site total/ tracer ratio emission rate
MC-1	MC-1	70.9	1.89	0.12	0.12	2.32	0.815
MC-Z	MC-14	78.1	0.99	0.34	0.01	2.00 *	0.495
MC-3	MC-20	77.2	1.63	0.45	0.18	2.95	0.552
MC-4	MC-5	74.2	2.31	0.19	0.14	3,36	0.687
MC-5	MC-16	79.3	1.85	0.56	0.18	4.16	0.445
RM-1	RM-7	81.9	0.22	0.11	0.09	0.584	0.368
RM-2	RM-8	74.5	4.43	0.02	0.02	1.70	2.60
RM-3	RM-1	76.4	0.13	0.67	0.69	0.442	0.303
RM-4	RM-3	74.9	0.11	0.21	0.00	0.839	0.137
RM-5	RM-2	74.5	0.09	0.35	0.33	0.240	0.392
RM-6	RM-5	74.5	0.74	0.41	0.42	0.421	1.75
RM-7	RM-14	74.5	0.27	0.26	0.26	0.368	0.736
RM-8	RM-19	76.2	0.29	0.82	0.79	1.08	0.266
RM-9	RM-12	74.5	0.38	0.05	0.05	0.864	0.436
RM-10	RM-4	76.2	2.86	0.01	0.00	0.080	35:7
AP-2	AP-23	97.6	1.28	0.68	0.35	0.270	4.74
ΔP-3	AP-43	97.0	4.75	0.62	0.59	4:12	1.15
4P-4	AP-37* - ·	97.0	1.36	0.44	0.42	0.769	1.92
AP-5	AP-18	97.0	0.39	0.74	0.69	0.288	1.37

<sup>&</sup>lt;sup>1</sup>MC, Midcontinent; RM, Rocky Mountain; AP, Appalachia. Different site numbers were used to identify the same sites in the [1] supplemental information depending on whether BHFS or tracer ratio measurements were under discussion.

<sup>&</sup>lt;sup>2</sup>On-site totals were calculated by [1] by combining measurements made by the BHFS with estimates of any sources not measured; these estimates were made using mathematical models for tanks as well as emission factors for compressors and any pneumatic controllers not directly measured.

<sup>3</sup>Calculated by this author from [1] supplemental information.

pronounced as the amount of the on-site emissions actually measured by the BHFS becomes a larger fraction of the total on-site emissions (measured and estimated). As seen in Table 3, for the high CH<sub>4</sub> sites where the sampler should function properly, the on-site measurements and estimates exceed the tracer measurements, but approach a ratio of one (complete agreement) as the amount of actual measurements increases. For the two sites with wellhead gas compositions, ≥97% where the measured equipment leaks (which should produce steady emissions as compared to pneumatic devices which might be intermittent) averaged 64% of the total on-site measurements and estimates, the on-site total still exceeds the tracer measurements but are within 17% (Table 3). However, for the sites with wellhead gas CH<sub>4</sub> concentrations <82%, there is a clear trend of increasing deficit of the on-site emissions compared to the tracer ratio measurements as the actual BHFS measurements become a larger part of the on-site total. For instance, for the nine sites with at least 20% of on-site emissions from BHFS measurements (for an average of 45% of the total on-site emissions measured by the BHFS), the on-site emissions are only 49% of the tracer measurements (Table 3). For the two sites that had greater than 67% of on-site emissions data actually measured by the BHFS (for an average of 75% of on-site emissions data measured by the BHFS), the on-site emissions are only 28% of the tracer measurements (Table 3).

Comparing the on-site data to the downwind tracer measurements provides two valuable insights. First, there were six sites in the Rocky Mountain region for which at least 20% of the on-site emissions were measured by the BHFS (for an average of 45% actual BHFS measurements) (Table 2). For these six sites, the on-site emissions average 48% of the tracer data. For the two sites in this

region with at least 67% of on-site emissions from actual BHFS measurements (and with BHFS measurements averaging 75% of the total on-site data), the on-site emissions were only 28% of the tracer measurements (Table 2). This provides clear evidence that the sampler actually did fail in the Rocky Mountain region, as opposed to any possible regional differences (discussed previously) that might have created an emission pattern of no high emitters at sites with lower CH<sub>4</sub> concentrations in the wellhead gas.

Additionally, the tracer measurements provide a method to estimate the magnitude of errors introduced in the data collected by [1] due to BHFS sensor transition failure. For all of the sites with wellhead gas compositions ≥97% CH<sub>4</sub> (where the sampler should operate correctly), the emission rates determined by on-site measurements exceeded those determined by the downwind tracer ratio measurements. Assuming that the tracer method accurately measured the total emissions from the sites surveyed (e.g., [8, 15, 16]), I concluded that the methods used in [1] overestimated the on-site sources that were not directly measured. Therefore, I calculated the error in BHFS measurements at sites with low CH4 wellhead gas composition by assuming the tracer ratio measurements are correct. I have also assumed for this analysis that the estimates of any onsite sources made by [1] are also correct, even though the tracer data indicate they may be too high, because this is conservative in the sense that correcting for this overestimate would increase the BHFS error calculated below. Given these assumptions, subtracting the on-site estimated emissions from the tracer ratio emissions gives the expected measurement total that should have been reported from the BHFS measurements. Comparing this expected measurement total to the actual

Table 3. Comparison of on-site measurements to tracer ratio measurements made by Allen et al. [1] categorized by wellhead gas CH<sub>4</sub> concentration.

Site category (number of sites in parentheses)	Average percentage of on-site emissions reported by BHFS	Total on-site emissions (reported by BHFS and estimated) (scfm CH <sub>4</sub> )	Total emissions measured by tracer (scfm CH <sub>4</sub> )	Ratio of on-site emissions to emissions measured by tracer
All sites (19)	37	26.0	26.8	0.97
Sites where BHFS measurements are expected	to be accurate (wellhead	gas composition ≥97% CH	i)	
All sites (4)	62	7.78	5.39	1.44
Sites with >50% BHFS measurements (3)	68	6.42	4.68	1.37
Sites with >50% equipment leaks (2)	64 (equipment	5.14	4.41	1.17
the specific control of the	leaks/on-site-total)			
Sites where BHFS measurements are expected	to underreport high emit	ters (wellhead gas composit	ion <82% CH <sub>a</sub> )	
All sites (15)	28	18.2	21.4	0.85
Sites with ≥5% BHFS measurements (13)	35	10.9	19.6	0.56
Sites with ≥20% BHFS measurements (9)	45	6.10	12.5	0.49
Sites with >50% BHFS measurements (3)	69	2.27	5.68	0.40
Sites with >67% BHFS measurements (2)	75	0.42	1.52	0.28

BHFS, Bacharach Hi-Flow Sampler

measurement total reported by the BHFS provides an estimate of the error in BHFS measurements made by Allen et al. [1].

Table 4 presents the results of this analysis, and shows that for the 13 sites with wellhead gas compositions <82% CH<sub>4</sub> and with at least 5% actual BHFS measurements (with an average of 35% of emission sources measured by BHFS; bottom half of Table 3), the actual measurement total of the BHFS is less than one-third of the expected total, and this appears consistent as sites with greater fractions of actual BHFS measurements are examined. For these sites, the emission rates for equipment leaks and pneumatics devices presented by [1] are approximately equal, so it is not possible to assign a larger error to one category or another. Additionally, the errors introduced by the sensor failure would be expected to vary from site to site depending on how many emitters were present with emission rates exceeding the sensor transition threshold ceiling. Nevertheless, for these 13 sites, the BHFS underreported emissions for equipment leaks and pneumatic devices on average by more than a factor of 3 (Table 4).

Although the magnitude of error due to BHFS sensor failure is not known for all the sites in [1], the tracer ratio measurements make clear that the BHFS measurements for sites with lower CH<sub>4</sub> content in the wellhead gas could be at least a factor of three too low. More precise estimates of errors in [1] are not possible because of the nature of the sensor failure. Unlike a simple calibration error, for which it might be possible to correct, when sensor transition failure occurs, it is not possible to know for any particular measurement if the failure has occurred, and if it has, what the resulting error was, since the reported emission rates could range from 20% to two orders of magnitude too low.

### **Implications**

Sensor transition failure is clearly apparent in the BHFS measurements made in the UT study by Allen et al. [1], as evidenced by the rare occurrence of high emitters at sites with lower CH<sub>4</sub> (<91%) content in the wellhead gas. The occurrence of this sensor transition failure was corroborated by field tests of the UT BHFS during which it exhibited this sensor failure, as well as by tracer ratio measurements made by [1] at a subset of sites with lower wellhead gas CH<sub>4</sub> concentrations. At this subset of sites, the tracer ratio measurements indicate that the BHFS measurements were too low by at least a factor of three. Because BHFS measurements were the basis of 98% of the inventory developed by [1] using their own measurements (and 41% of their total compiled inventory), the inventory clearly underestimates CH<sub>a</sub> emissions from production sites. However, the extent of this error is difficult to estimate because the underreporting of emission rates due to BHFS sensor transition failure at any given site would vary depending on sampler performance and on how many high emitters were present at that site. Estimating this error is further complicated by the fact that the data set collected for pneumatic devices by [1] was an emitter data set; this might offset the effect of underreported high emitters in their pneumatic device emission factors. Finally, although real differences may exist in regional emission rates, the UT data set [1] should not be used to characterize them because the occurrence of sensor failure clearly varied between regions due to variations in wellhead CH4 compositions, which may mask any actual regional differences that existed.

Although the performance of the BHFS may vary between instruments or with sensor age or calibration vintage, this analysis of the [1] data set shows that measurements made using a BHFS for NG streams with CH<sub>4</sub> content

Table 4. Estimation of underreperting in Allen et al. [1] BHFS measurements of  $CH_a$  emission rates at sites with low  $CH_a$  well head gas composition (<82%), using downwind tracer measurements (from Table 3).

Minimum percentage of on-site emissions reported by BHFS	Average percentage of on-site emissions reported by BHFS	No. of sites	Total emissions measured by tracer (scfm CH <sub>4</sub> )	On-site emissions estimated by UT (excludes BHFS measure- ments) (scfm CH <sub>4</sub> )	Expected BHFS measurement total (tracer – on-site estimates). (scfm CH <sub>4</sub> )	Emissions reported by BHFS (scfm CH <sub>4</sub> )	Ratio of reported BHFS to expected BHFS
≥5	35	13	19.63	7.09	12.54	3.81	0.30
≥20	45	9	12.50	3.34	9.16	2.76	0.30
>50	69	3	5.68	0.71	4.97	1.56	0.31
>67	75	2.	1.52	0.11	1.42	0.31	0.22

BHFS, Bacharach Hi-Flow Sampler, UT, University of Texas.

up to 97% could lead to severe underreporting of NG leaks. That this failure can occur at such high CH<sub>4</sub> concentrations, which are close to the higher end of those found in transmission and distribution systems, indicates that past measurements in all segments of the NG supply chain could have been affected by this problem. Because the BHFS sensor transition failure phenomenon is not fully understood, it is not known how much this error may have affected past measurements of CH<sub>4</sub> emission rates. Two factors preclude this: first, the performance of any individual BHFS may vary, and second, once sensor transition failure occurs, there is no way to determine the magnitude of the measurement error in the absence of an independent flux or concentration measurement.

If BHFS sensor transition failure has occurred during industry monitoring at transmission, storage, and processing compressor stations where the BHFS is approved for leak measurements mandated by the USEPA Subpart W Greenhouse Gas Reporting Program (GHGRP) [23], then these errors could be larger than those observed at production sites. Leaks at transmission, storage, and processing compressor stations commonly exceed 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) (the approximate threshold for BHFS sensor transition failure) and in some cases may range from 10 to over 100 scfm. Because the largest 10% of leaks typically account for 60-85% of the total leak rate at a given facility [9, 25], sensor transition failure in the BHFS could bias CH, emission inventories compiled by the USEPA GHGRP substantially low since the most significant leaks could be underreported. Additionally, leak measurements using the BHFS may be used to guide repair decisions at NG-facilities, and underreporting of leaks could compromise safety if large leaks remain unrepaired as a result.

Finally, it is important to note that the BHFS sensor failure in the UT study [1] went undetected in spite of the clear artifact that it created in the emission rate trend as a function of wellhead gas CH<sub>4</sub> content and even though the authors' own secondary measurements made by the downwind tracer ratio technique confirmed the BHFS sensor failure. That such an obvious problem could escape notice in this high profile, landmark study highlights the need for increased vigilance in all aspects of quality assurance for all CH<sub>4</sub> emission rate measurement programs.

### **Acknowledgments**

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### **Conflict of Interest**

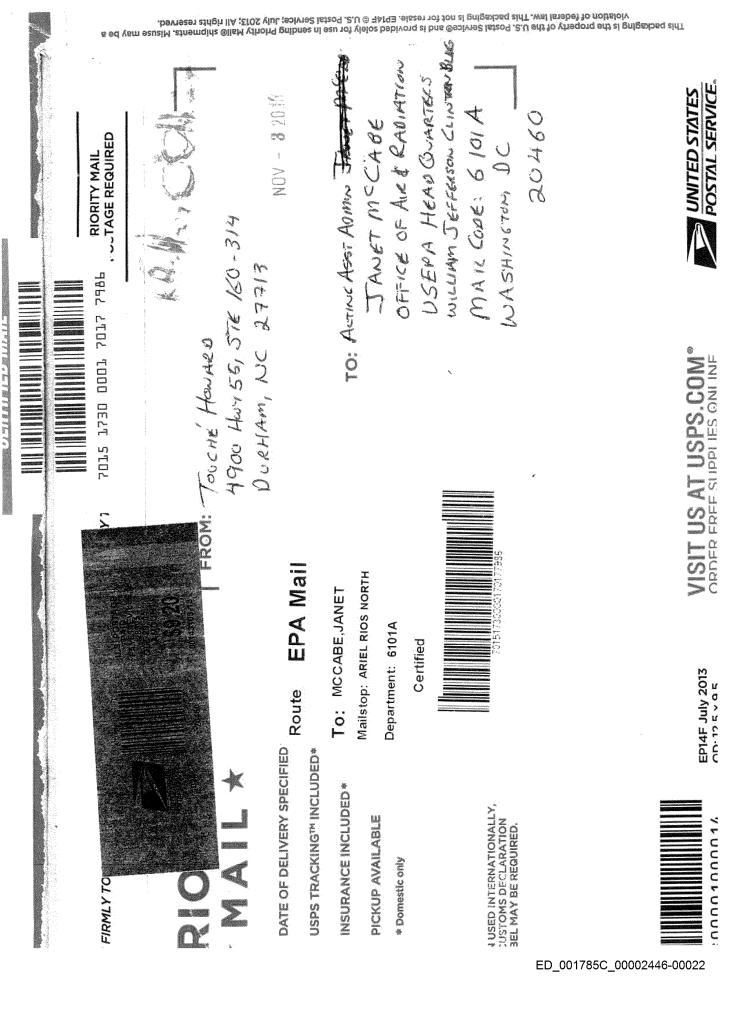
The author is the developer of high flow sampling technology (US Patent RE37, 403) and holds a license to use it for any purpose; however, he does not sell high flow samplers nor was he involved in the development of the Bacharach Hi-Flow Sampler.

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Climate Change Division

Weitz, Melissa[Weitz.Melissa@epa.gov]; Macpherson, Alex[Macpherson.Alex@epa.gov]; To: Moore, Bruce[Moore.Bruce@epa.gov]; Thompson, Lisa[Thompson.Lisa@epa.gov]; Hambrick, Amy[Hambrick.Amy@epa.gov] McKittrick, Alexis[McKittrick.Alexis@epa.gov] Cc: Thoma, Eben From: Sent: Fri 2/5/2016 5:47:44 PM Subject: RE: calling into Hi Flo meeting? Yes, I will but I have a call at 1:00 pm and may be a tad late. From: Weitz, Melissa **Sent:** Friday, February 05, 2016 12:47 PM **To:** Macpherson, Alex <Macpherson.Alex@epa.gov>; Moore, Bruce <Moore.Bruce@epa.gov>; Thoma, Eben <Thoma.Eben@epa.gov>; Thompson, Lisa <Thompson.Lisa@epa.gov>; Hambrick, Amy < Hambrick. Amy @epa.gov> Cc: McKittrick, Alexis < McKittrick. Alexis@epa.gov> **Subject:** calling into Hi Flo meeting? Hi, I wanted to get a sense of how many folks will be on the line for the Touche call at 1:30. Can you let me know if you're able to participate? Thanks! Melissa Melissa Weitz

ED\_001785C\_00002831-00001

U.S. Environmental Protection Agency

(202) 343-9897

Weitz.Melissa@epa.gov

ED\_001785C\_00002831-00002

From: Thoma, Eben

Location: DCRoomWJCS4228AOAP/DC-OAR-OAP

Importance: Normal

Subject: Accepted: hold for meeting on Hi-Flo Sampler with Touche Howard

**Start Date/Time:** Tue 1/26/2016 4:00:00 PM Tue 1/26/2016 5:00:00 PM

Thoma, Eben From:

DCRoomWJCS4228AOAP/DC-OAR-OAP Location:

Normal Importance:

Subject: Accepted: meeting on Hi-Flo Sampler with Touche Howard Start Date/Time: Fri 2/5/2016 6:30:00 PM

**End Date/Time:** Fri 2/5/2016 7:30:00 PM

To: Weitz, Melissa[Weitz.Melissa@epa.gov]

From: Thoma, Eben

**Sent:** Mon 1/25/2016 6:19:37 PM

Subject: RE: hold for meeting on Hi-Flo Sampler with Touche Howard

Hi Melissa,

Can I invite my contractor with Jacobs engineering to this discussion?

Thanks,

Eben

----Original Appointment-----

From: Weitz, Melissa

Sent: Wednesday, December 23, 2015 4:36 PM

To: Weitz, Melissa; DeFigueiredo, Mark; Waltzer, Suzanne; McKittrick, Alexis; Macpherson, Alex;

Moore, Bruce; Thoma, Eben; Thompson, Lisa; Hambrick, Amy; Banks, Julius; Irving, Bill

Subject: hold for meeting on Hi-Flo Sampler with Touche Howard

When: Tuesday, January 26, 2016 11:00 AM-12:00 PM (UTC-05:00) Eastern Time (US & Canada).

Where: DCRoomWJCS4228AOAP/DC-OAR-OAP

Call in Ex. 6 - Personal Privacy; code { Ex. 6 - Personal Privacy

A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

From: Sent:	David Lyon[dlyon@edf.org] Lucy Kalunde[lkalunde@edf.org]; Kelsey Monk[kmonk@edf.org]; Brantley, ntley.Halley@epa.gov] Thoma, Eben Wed 1/8/2014 4:00:50 PM RE: Barnett Campaign meeting January 23 & 24 in Denver
Many tha	nks David.
For this tr	rip, EPA will pay for Eben and EDF will cover Halley.
Halley,	
Please pro	ovide information below to Lucy as soon as you can.
Thanks,	
Eben	
Sent: Wed To: Thoma Cc: Lucy h	vid Lyon [mailto:dlyon@edf.org] Inesday, January 08, 2014 10:29 AM a, Eben Kalunde; Kelsey Monk RE: Barnett Campaign meeting January 23 & 24 in Denver
Eben,	

Yes, EDF will pay for Halley Brantley's attendance to the Denver meeting if EPA can cover your expenses. We look forward to both of your participation in the workshop.

Please have Halley send the following information to Lucy Kalunde (<u>lkalunde@edf.org</u>).

- 1. Name (First, Middle, Last)
- 2. DOB
- 3. Preferred Contact Phone #
- 4. Preferred Airport (realize some people may be travelling already)
- 5. Any other important info we'll need to book a good flight for them.

Best Regards,

David

From: Thoma, Eben [mailto:Thoma.Eben@epa.gov]

Sent: Tuesday, January 07, 2014 6:27 AM

To: David Lyon Cc: Lucy Kalunde

Subject: RE: Barnett Campaign meeting January 23 & 24 in Denver

Thanks David,

I have a question for you. Our new researcher (Halley Brantley) just started and will be heavily involved in our work together. She basically will be our primarily horsepower here. In my opinion, our collaboration would benefit greatly from her attendance at the Denver workshop.

Unfortunately, we currently don't have a mechanism to pay for her travel. If I can get EPA to pay for my travel to the Denver meeting, Do you think it may be possible for EDF to pay for

Halley's trip (just this time)? EDF would still be sponsoring only one person's trip from the EPA team. I understand if this is not possible and frankly, I not sure we have the funds to pay for my trip but it is worth asking.
Thanks,
Eben
From: David Lyon [mailto:dlyon@edf.org] Sent: Monday, January 06, 2014 3:31 PM To: Thoma, Eben Cc: Lucy Kalunde Subject: RE: Barnett Campaign meeting January 23 & 24 in Denver
Eben,
I am glad you can attend our Barnett campaign meeting. The meeting will be at the Marriott Denver Airport at Gateway (16455 E. 40th Circle, Aurora, CO 80011).
David
From: Thoma, Eben [mailto:Thoma.Eben@epa.gov] Sent: Tuesday, December 31, 2013 10:14 AM To: Lucy Kalunde Cc: David Lyon Subject: FW: Barnett Campaign meeting January 23 & 24 in Denver
Hi Lucy,
Just resending the below email not because I messed-up your address the first time.

It looks like Southwest Airlines is the government contract carrier from RDU to Denver so I should be able to get a pretty good ticket prices through the Government system. I will let you know when I conform the cost.

Also,

I need to know the exact location of the meeting in order to complete our mandatory ethics review from for invited travel. Please let me know the meeting site location and room rates as soon as you can.

Thanks,

Eben

From: Thoma, Eben

Sent: Sunday, December 29, 2013 11:03 AM

To: David Lyon; Lucy@Kalunde

Subject: Re: Barnett Campaign meeting January 23 & 24 in Denver

Hi David and Lucy,

I would like to try to attend. Just to confirm, EDF is offering to reimburse EPA for this as it has done for past meetings in this series (please confirm). This kind offer would be greatly appreciated as our travel budgets are slim at present.

As in the past, I will need to make my own reservations through EPA travel services and EPA will get in touch with EDF after the trip. I would plan on taking Southwest Flt 1030 from RDU arriving at 11:25 AM on 1/23 and I would need to take FLT 2608 departing Denver at 5:00 pm 1/24 so I would need to leave a tad bit early. I can get back to you on the cost of these flts in a couple of days. I am going to try to get the web deal but our travel folks may not allow me to do

this.

It may be possible for you to book the flts for me at the web fare but this is a little complicated and will (as with the trip) need to go through the EPA ethics review process. This will take some time and I will get back to you as soon as I know something.

Let me now if this generally sound okay and sorry for the extra bother.

Thanks,

Eben

From: David Lyon < dlyon@edf.org>

Sent: Thursday, December 19, 2013 4:49:46 PM

To: Thoma, Eben; Birnur Guven (bguven@harcresearch.org); Natalie Pekney; amy.townsendsmall@uc.edu; anna.karion@noaa.gov; Anthony O'Brien; Bill Hirst; Brian Lamb; Brian Nathan; Charles Boller; Chris Rella; Clark, Nigel; Colm Sweeney; Darrell Anderson; Dave Schaefer; David Steele; david.lary@utdallas.edu; 'Derek Johnson'; 'desiree.plata@duke.edu'; Don Blake; Drew Nelson; ecrosson@picarro.com; Eric Kort; 'Gabrielle Petron - NOAA Affiliate'; Isobel Simpson; 'Jackson@duke.edu'; 'Joe.von\_Fischer@colostate.edu'; Josette Marrero; Kelsey Monk; Ken Davis; lanxin.lindsay@gmail.com; Malcolm Argyle; mcambali@purdue.edu; McKain, David; Morgan Gallagher; mzondlo@princeton.edu; 'plaine@uh.edu'; 'pshepson@purdue.edu'; Ramon Alvarez; Rob Bennett; Robert Harriss; Sol Meyer; Steve Conley; Steve Edburg; Talbot, Robert; Tegan Lavoie; Thomas Lauvaux; Tom Ferrara; Touche Howard; Tracy Tsai; Daniel Jacob; Doug Blewitt; Francis O'Sullivan; Steve Hanna

Cc: Lucy Kalunde; Kelsey Monk

Subject: Barnett Campaign meeting January 23 & 24 in Denver

Greetings,

The Barnett Campaign meeting will be January 23 & 24 in Denver. Yes, I'm aware that Denver is cold in January, but it is the most convenient location to bring people together. EDF will book a block of rooms and meeting place at a hotel near the Denver International Airport. We plan on starting the meeting around 1:00 pm Thursday and ending around 4:00 pm Friday, which should allow most people to stay only one night at the hotel. Lucy Kalunde at EDF will book your flights. Please let us know if you are attending and send Lucy (<a href="mailto:lkalunde@edf.org">lkalunde@edf.org</a>) the following information as soon as possible.

- 1. Name (First, Middle, Last)
- 2. DOB
- 3. Preferred Contact Phone #
- 4. Preferred Airport (realize some people may be travelling already)
- 5. Any other important info we'll need to book a good flight for them.

Thanks,

David



David Lyon

Research Analyst

**Environmental Defense Fund** 301 Congress Avenue, Suite 1300

Austin, TX 78701 (512) 691-3414 dlyon@edf.org

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To: David Lyon[dlyon@edf.org]; Lucy@Kalunde[Lucy@Kalunde]

From: Thoma, Eben

**Sent:** Sun 12/29/2013 4:02:56 PM

Subject: Re: Barnett Campaign meeting January 23 & 24 in Denver

Hi David and Lucy,

I would like to try to attend. Just to confirm, EDF is offering to reimburse EPA for this as it has done for past meetings in this series (please confirm). This kind offer would be greatly appreciated as our travel budgets are slim at present.

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Let me now if this generally sound okay and sorry for the extra bother.

Thanks,

Eben

From: David Lyon <dlyon@edf.org>

Sent: Thursday, December 19, 2013 4:49:46 PM

To: Thoma, Eben; Birnur Guven (bguven@harcresearch.org); Natalie Pekney; amy.townsend-small@uc.edu; anna.karion@noaa.gov; Anthony O'Brien; Bill Hirst; Brian Lamb; Brian Nathan; Charles Boller; Chris Rella; Clark, Nigel; Colm Sweeney; Darrell Anderson; Dave Schaefer; David Steele; david.lary@utdallas.edu; 'Derek Johnson'; 'desiree.plata@duke.edu'; Don Blake; Drew Nelson; ecrosson@picarro.com; Eric Kort; 'Gabrielle Petron - NOAA Affiliate'; Isobel Simpson; 'Jackson@duke.edu'; 'Joe.von\_Fischer@colostate.edu'; Josette Marrero; Kelsey Monk; Ken Davis; lanxin.lindsay@gmail.com; Malcolm Argyle; mcambali@purdue.edu; McKain, David; Morgan Gallagher; mzondlo@princeton.edu; 'plaine@uh.edu'; 'pshepson@purdue.edu'; Ramon Alvarez; Rob Bennett; Robert Harriss; Sol Meyer; Steve Conley; Steve Edburg; Talbot, Robert; Tegan Lavoie; Thomas Lauvaux; Tom Ferrara; Touche Howard; Tracy Tsai; Daniel Jacob; Doug Blewitt; Francis O'Sullivan; Steve Hanna Cc: Lucy Kalunde; Kelsey Monk

Subject: Barnett Campaign meeting January 23 & 24 in Denver

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- 5. Any other important info we'll need to book a good flight for them.

Thanks,

David

Million Million

**David Lyon** 

Research Analyst

**Environmental Defense Fund** 301 Congress Avenue, Suite 1300

Austin, TX 78701 (512) 691-3414 dlyon@edf.org This e-mail and any attachments may contain confidential and privileged information. If you are not the intended recipient, please notify the sender immediately by return e-mail, delete this e-mail and destroy any copies. Any dissemination or use of this information by a person other than the intended recipient is unauthorized and may be illegal.

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For further information, please contact the EPA Call Center at (866) 411-4EPA (4372). The TDD number is (866) 489-4900.

To: Gunning, Paul[Gunning.Paul@epa.gov]

Cc: Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]; DeFigueiredo,

Mark[DeFigueiredo.Mark@epa.gov]; Eisele, Adam[Eisele.Adam@epa.gov]

From: Weitz, Melissa

**Sent:** Thur 1/5/2017 10:53:09 PM

Subject: participant list for oil and gas GHG Inventory stakeholder webinar

2017 GHGI RevUnderConsid STAKEHOLDER WEBINAR 1.4.pptx

Stakeholder Webinar Petroleum and Natural Gas Systems Attendee Report.xls

We held the webinar on updates for oil and gas in the GHG Inventory on December 20, and repeated the webinar on January 4.

The webinar was well-attended (94 total attendees), and the participants asked a handful of straightforward questions, mostly for clarification on the updates.

I've attached the participant list and the webinar slides.

We anticipate posting memos for stakeholder feedback on the updates next week.

Melissa

## Updates Under Consideration for the 2017 GHGI

Stakeholder Webinar
December 20 (and January 4)

### OVERVIEW

- Background and process
- Production segment updates
- Processing segment updates
- Providing comments

Transmission and storage segment updates

## **BACKGROUND AND PROCESS**

- New data available
- GHGRP

DrillingInfo

- EDF series of studies
- ARB
- EPA considering updates for Production, Processing, and Storage
- Memos
- Public review draft

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## PRODUCTION TOPICS

- Equipment Counts
- Liquids Unloading
- Tanks and Associated Gas Venting & FlaringGathering & Boosting Episodic Events

# PRODUCTION SEGMENT EQUIPMENT COUNTS

UI

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# **EQUIPMENT COUNTS: BACKGROUND**

## **GHGRP Equipment Leaks Data**

- For 2016 GHGI, EPA revised the AFs (equipment per well) using subpart W RY2014 data for equipment counts and well counts
- Certain assumptions were applied (e.g. to distinguish between gas and
- Starting in RY2015, GHGRP reporters also provide data on production type (gas or oil)

### **Well Counts**

- Latest DrillingInfo dataset
- Revisions for Texas
- World Oil

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# EQUIPMENT COUNTS: RY2014 VS RY2015

Equipment Type	RY2014 Subpart W Count (Basis of 2016 GHGI)	RY2015 Subpart W Count
Wells		
Wells (NG)	223,192	307,737
Wells (Petro)	275,831	219,433
Separators		
Separators (NG)	149,912	210,836
Separators (Petro)	119,479	87,260
Heaters (NG)	48,460	63,523
Dehydrators (NG)	8,380	8,195
Meters/piping (NG)	256,340	263,870
Compressors (NG)	23,740	24,090
Heater-treaters (Petro)	34,902	51,364
Headers (Petro)	44,880	52,872

## LIQUIDS UNLOADING

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# LIQUIDS UNLOADING IN 2016 GHGI

- Updates made in 2013 GHGI (1990-2011)
- Based on API/ANGA survey
- Respondents provided GHGRP data in advance of EPA publication
- Data showed more widespread use of emissions control technologies and that duration of emissions from liquids unloading activities was shorter than had been assumed in the previous
- EPA used API/ANGA data to estimate activity data and emissions for 2010
- EPA calculated from API/ANGA the % of wells that may conduct liquids unloadings. For 1990-2009, EPA applied an assumption that in 1990 no plunger or artificial lifts were in place. EPA then interpolated between 1990 and 2010 for each region.
- **GHGRP** data set In GHGI Planned Improvements, noted intent to revisit calculations, with
- Data available from GHGRP for update
- Options for development of 1990-2010 estimates

9

# LIQUIDS UNLOADING ACTIVITY DATA

Data Source	Year	Total # Gas	With P	With Plunger Lifts	Without	Without Plunger Lifts
		Wells	# Wells Vented	% of Wells That Vented	# Wells Vented	% of Wells That Vented
Subpart W	2011		42,826		26,679	
	2012		34,136		25,262	
	2013		30,922		27,723	
	2014		26,859		23,068	
	2015	307,737	30,757	10.0%	20,886	6.8%
<b>2016 GHGI</b> 2014	2014	456,140	22,477	4.9%	37,912	8.3%

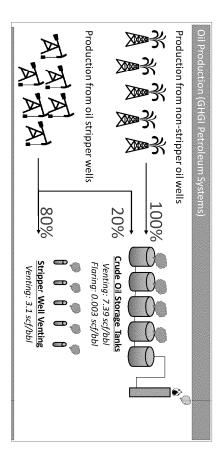
# LIQUIDS UNLOADING EFs (scfy/well)

Data Source	Year	With Plunger Lifts Without Plunger	Without Plunger
			Lifts
Subpart W	2011	205,387	149,023
	2012	166,144	133,689
	2013	162,485	160,865
	2014	104,863	194,842
	2015	74,236	168,647
	Average	148,589	160,411
2016 GHGI	2014	200,791	260,030

# TANKS AND ASSOCIATED GAS VENTING & FLARING

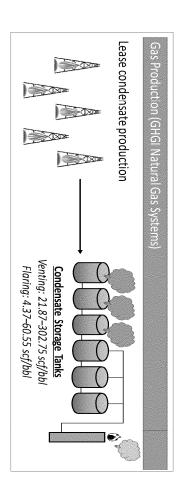
## **CURRENT GHGI: OIL WELLS**

- Non-stripper wells: Apply tank EF (scf/bbl) to 100% of nonstripper well oil production
- Stripper wells: Production split between well venting and tanks using 80/20 split
- Stripper well venting EF (scf/bbl) applied to 80%
- Tank EF (scf/bbl) applied to 20%
- Tank EF includes malfunctioning dump valve emissions



## **CURRENT GHGI: GAS WELLS**

- Apply tank EFs (scf/bbl) to 100% of condensate production
- Apply uncontrolled tank EF to 50% of production
- Apply controlled tank EF to 50% of production
- Tank EFs include malfunctioning dump valve emissions, for 2 regions



# **CURRENT GHGI: GATHERING & BOOSTING**

- For certain sources, gathering and boosting is integrated with well pad activities in the production segment of Natural Gas Systems in
- A gathering and boosting station facility-level EF was implemented in 2016 GHGI
- Based on Marchese study data
- This EF includes tank emissions at gathering stations
- Updates under consideration ensure that production tanks methodology estimates emissions for well pad tanks only

## **AVAILABLE SUBPART W DATA**

- Onshore oil and gas production includes all equipment "on a single well-pad or associated with a single well-pad"
- Tanks
- Large tanks: ≥10 bbl/day
- Small tanks: <10 bbl/day (equivalent to stripper well definition)
- Associated Gas Venting & Flaring

## TANKS: ACTIVITY COMPARISON

Parameter	Condensate Production	Oil Production
Throughput Basis Option	s Option	
2014 National Throughput (MMbbl)	277	2,998
Production (MMbbl) Reported for RY2015 Under Subpart W	277	2,160
Percent of National Reported Under Subpart W	100%*	72%*
Percent of Total Subpart W Production Reported Under Tanks	85%	62%
Tank Basis Option (well counts as key activity data)	s as key activity data)	
2015 National Well Count	440,496	607,559
Count of Wells Reported for RY2015 Under Subpart W	307,737	219,433
Percent of National Reported Under Subpart W	70%	36%
Percent of Total Subpart W Wells Reported Under Tanks	40%	71%

<sup>\*</sup>Comparison of 2015 GHGRP and 2014 (most recent available) national data on throughput

## THROUGHPUT-BASED OPTION EFs (scf/bbl)

Tank Category	Conder	<b>Condensate Tank Throughput</b>	oughput	Oil Ta	Tank Throughput	
	Subpart W - Large Tanks	Subpart W - Subpart W - Large Tanks Small Tanks	GHGI (a)	Subpart W - Large Tanks	Subpart W - Small Tanks	GHGI
Tanks with Flaring	0.28	0.34	4.4 or 60.6	0.35	0.09	7.39
Tanks with VRU	0.21	n/a		0.47	n/a	
Tanks without Controls	8.73	n/a	21.9 or 302.8	7.9	n/a	
Tanks without Flares	n/a	24.8		n/a	2.3	
Malfunctioning Dump Valves	0.02	n/a	(a)	0.15	n/a	
ALL TANKS	1.8	16.6	56.3	2.0	1.7	

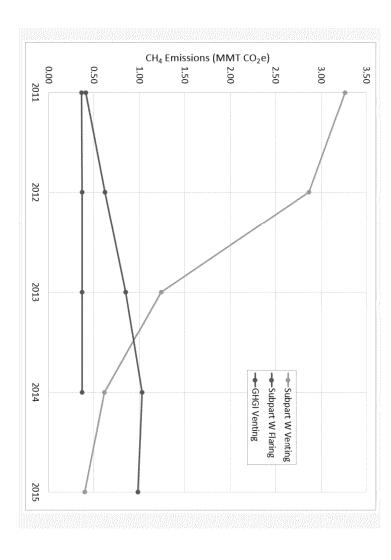
a) Larger GHGI EFs include malfunctioning dump valve emissions for 2 NEMS regions

## TANK-BASED OPTION EFs (scf/tank)

Tank Category	Condens	Condensate Tanks	011	Oil Tanks
	Subpart W EF - Large Tanks	Subpart W EF - Subpar	Subpart W EF - Large Tanks	Large Tanks   Small Tanks
Tanks with Flaring	2,242	393	3,755	197
Tanks with VRU	1,774	n/a	10,854	n/a
Tanks without Controls	33,201	n/a	51,192	n/a
Tanks without Flares	n/a	10,951	n/a	4,236
Average for all Tanks	11,915	9,242	20,739	3,253

Category	Condensate	0:1
	Production	Production
Malfunctioning	21,175	154,874
Dump Valves		
(scf/separator)		

# ASSOCIATED GAS: SUBPART W VS GHGI



19

### **ASSOCIATED GAS**

Subpart W Activity Factor Development

 Determine number of wells applicable to associated gas venting and flaring

12%	25,739	219,433	2015
Flare	Flaring Wells	Wells	
% of Total that Vent or	Total # Venting &	Total Oil	Year

### **ASSOCIATED GAS**

## Subpart W Activity Factor Development

Determine number of associated gas wells that vent and flare

Year	Total # Venting &	Associated	Associated Gas Venting	Associated Gas Flaring	Gas Flaring
	Flaring Wells	# Venting Wells % of Total that Vent	% of Total that Vent	# Flaring Wells   % of Total that   Flare	% of Total that Flare
2011	14,491	8,863	61%	5,628	39%
2012	15,813	8,554	54%	7,259	46%
2013	15,860	6,980	44%	8,880	56%
2014	19,453	7,264	37%	12,189	63%
2015	25,739	4,286	17%	21,453	83%

### **ASSOCIATED GAS**

### Subpart W Emission Factors

 Subpart W EFs are much higher than GHGI EF (which is only applicable to stripper wells)

Year	Subpart W Venting EF	Subpart W Flaring EF	GHGI Venting EF
	(mscfy/well)	(mscfy/well)	(mscfy/well)
2011	765	151	2.35
2012	696	178	
2013	369	198	
2014	176	176	
2015	193	95	

## GATHERING AND BOOSTING EPISODIC EVENT **EMISSIONS**

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- Blowdown data were specifically excluded from Marchese et al. data used to develop station-level EF
- Marchese developed a separate emissions estimate specific to episodic events
- Blowdowns of pressurized equipment, compressor engine starts utilizing gaspneumatic starters, pig launch and receive operations
- Marchese EF = 37 MT  $CH_4$ /station
- Considering update to apply Marchese EF and/or review RY2016 subpart W data when available for updates

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### STAKEHOLDER FEEDBACK (1 OF 2) PRODUCTION-KEY REQUESTS FOR

### Tanks

- The EPA seeks feedback on the throughput-based or tank-based subpart W GHGI time series EF and AF data options, and on how to best estimate emissions over the
- Subpart W only includes reporting of malfunctioning dump valves from are more or less likely to have malfunctioning dump valves large tanks. The EPA seeks stakeholder feedback on whether small tanks
- discrepancy. from tanks. GHGRP data is showing lower, not higher emissions than the Recent studies have observed (but not quantified) very high emissions GHGI. The EPA is seeking stakeholder feedback on this apparent

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### STAKEHOLDER FEEDBACK (2 of 2) PRODUCTION-KEY REQUESTS FOR

### **Associated Gas Venting and Flaring**

- associated gas venting and flaring to national representation for use in the GHGI. The EPA seeks stakeholder input on approaches for scaling subpart W data for
- The EPA seeks stakeholder input on approaches for populating the GHGI time series using subpart W data for associated gas venting and flaring.

### **Equipment Counts**

- The EPA seeks stakeholder input on the latest DrillingInfo data set.
- The EPA seeks feedback on whether and how to distinguish between stripper and non-stripper oil wells in applying the subpart W data.

### **Liquids Unloading**

The EPA seeks stakeholder feedback on approaches for calculating liquids unloading emissions and activity using subpart W data.

### UNDER CONSIDERATION FOR GAS PROCESSING REVISIONS THE 2017 GHGI

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# KEY BACKGROUND ON CURRENT METHODS

- from the Natural Gas Industry" GRI/EPA 1996, with some exceptions. Emission factors and activity data are based "Methane Emissions
- Centrifugal compressor wet seal emission factors from "Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry" Proceedings of the 24th World Gas Conference. October 2009
- Centrifugal compressor dry seal emission factors from Gas STAR partner data. October 2006
- Methane from flares not included in the estimation methodology.
- Gas STAR reported data used for reductions

## AND MARCHESE ET AL. NEW DATA AVAILABLE- MITCHELL ET AL.

- Mitchell conducted plume measurements down wind of 16 gas plants in 2014.
- Owned by 3 companies
- Ranged from 2 to 972 MMscfd
- Marchese extrapolated the Mitchell et al. data to the national level, based upon a national inventory of gas plant sizes

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## **NEW DATA AVAILABLE-- GHGRP**

- Annual data reporting since 2011.
- Includes over 450 processing plants ranging in size from 1 to 1800 MMsctd.
- Includes a majority of plants and throughput.
- Calculation requirements vary by source and include direct measurement, engineering calculations, and emission factors
- Includes data for most of the source categories in the GHG Inventory
- Does not include methane from dry compressor seals, AGR vents or pneumatic devices.

# COMPARISON OF AVAILABLE DATA SOURCES

(National estimates, MMTCO2e)

Emission Source	2016 GHGI	GHGRP Throughput Scale-	GHGRP Plant Scale-up	Marchese Option
		늉		
Non-compressor Fugitives	0.9	0.3	0.3	12.7
Reciprocating Compressor	11.9	1.3	1.4	
Centrifugal Compressors (wet seals)	6	0.4	0.4	
Centrifugal Compressors (dry seals)	1.4			
AGR Vents	0.4			
Kimray Pumps and Dehydrator vents		0.3	0.4	
Pneumatic Devices	0.1			
Reciprocating and turbine Engine Exhaust	5.2	0.0	0.0	
Flares	0	0.4	0.4	
Blowdowns and Venting	1.3	0.7	0.7	P

For certain sources, e.g., where GHGRP data are unavailable, EPA is considering retaining the current GHGI data

## APPROACHES UNDER CONSIDERATION FOR 2017 GHGI

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### **GHGRP**

- Scale GHGRP to a national level (plant or throughput basis)
- GHGRP data years to include
- Use 2015 GHGRP only
- Use an average of 2011-2015 GHGRP
- Use annual GHGRP data for 2011 to 2015
- Supplement with GHGI factors for dry compressor seals, AGR, pneumatics, and potentially use GHGI exhaust factor
- Interpolate between 1992 and 2011 or 2015 depending on how GHGRP data are

### Marchese

- Develop a plant-wide emission factor based on Marchese for
- Use with plant populations 2014 and later years
- Include Marchese estimate of missing sources
- Interpolate between 1992 2014 using plant population

### STAKEHOLDER FEEDBACK PROCESSING-KEY REQUESTS FOR

- GHGRP versus Marchese data sets
- GHGRP data years for GHGRP approach
- Approaches for scaling current GHGRP emissions to the national level; throughput versus plant population for GHGRP approach
- Approaches for interpolating between 1992 and current emissions; throughput versus plant population
- For combustion exhaust sources, potential use of the existing GHGI emission factors (scf/HPhr) GHGRP activity factors (HPhr/mmscf)

## ALISO CANYON

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# ALISO CANYON EMISSIONS ESTIMATE

- Estimate available from ARB
- Calculated using data from multiple methods
- Separated estimate into 2015 and 2016 emissions
- Leak estimate for 2015 is 78,350 tons of methane
- Very minor other emissions occurring at the time of measurements
- E.g. other minor equipment leaks
- Preliminary estimate is that any double counting would be <1% of estimate
- Addition of this source increases storage well emissions from 0.4 MMT CO2e to 2.3 MMT CO2e for 2015

### **NEXT STEPS**

- Posting of memos with additional details on updates under consideration
- Public review draft early 2017
- Final 2017 GHG Inventory April 2017

To: Gunning, Paul[Gunning.Paul@epa.gov]; Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Weitz,

Melissa[Weitz.Melissa@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Irving,

Bill[Irving.Bill@epa.gov]; Banks, Julius[Banks.Julius@epa.gov]; Waltzer,

Suzanne[Waltzer.Suzanne@epa.gov]; Franklin, Pamela[Franklin.Pamela@epa.gov]

From: DeLuca, Isabel

**Sent:** Wed 6/8/2016 6:07:55 PM

Subject: FW: ACTION: Wash Post RE: methane complaint

EPA-OIG NCWARN Complaint 6-8-16.pdf

ATT00001.htm

Touche Howard, along with the group NC Warn, has filed a complaint to EPA's OIG that saying that EPA is grossly underestimating methane emissions from natural gas production sites. The complaint claims that EPA has been wasteful with resources by using flawed studies that rely on data from Bacharach High-Flow samplers, and asks the OIG to investigate. A PDF of the complaint is attached.

Washington Post has asked EPA to comment,

### Ex. 5 - Deliberative Process

### Ex. 5 - Deliberative Process

I'll send the draft response to WaPo for your review once it's drafted.

Thanks,

Isabel

From: Jones, Enesta

Sent: Wednesday, June 08, 2016 1:08 PM

To: Drinkard, Andrea < Drinkard. Andrea@epa.gov>; DeLuca, Isabel < DeLuca. Isabel@epa.gov>;

Davis, Alison <Davis.Alison@epa.gov>
Cc: Jones, Enesta <Jones.Enesta@epa.gov>

Subject: ACTION: Wash Post RE: methane complaint

Reporter: Darryl Fears

Hard DDL: 2:30 p.m. today

I'm looking into a story based a report on a complaint filed by a group called NC Warn against EPA regarding underreporting of Methane emissions, particularly at natural gas production sites. Can you guide me to the right person to speak with about this?

The complaint is centered on a device to detect emissions that malfunctions, according to NC Warn and Touche Howard, the person who developed the software that inspired it. NC Warn and Howard say the use of the device undermines the findings of the study by the former head of an EPA Science Advisory Council that said levels of methane emissions at natural gas sites are safe. NC Warn is a small group, but this complaint, supported by Howard, seems to have weight.



### Building people power for climate & energy justice

**COMPLAINT** and request for investigation of fraud, waste and abuse by a high-ranking EPA official leading to severe underreporting and lack of correction of methane venting and leakage throughout the US natural gas industry

Filed on June 8, 2016 With the Office of Inspector General of the **US Environmental Protection Agency** by **NC WARN** 

> Jim Warren, Executive Director (919) 416-5077

ncwarn@ncwarn.org

John Runkle, Counsel (919) 942-0600 jrunkle@pricecreek.com

**NC WARN** P.O. Box 61051 Durham, NC 27715

P.O. Box 61051, Durham, NC 27715 • 919-416-5077 • www.ncwarn.org

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References

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### Building people power for climate & energy justice

June 8, 2016

Inspector General Arthur A. Elkins, Jr. U.S. Environmental Protection Agency Office of Inspector General 1200 Pennsylvania Avenue, N.W. (2410T) Washington, DC 20460

Re: COMPLAINT and request for investigation of fraud, waste and abuse by a high-ranking EPA official leading to severe underreporting and lack of correction of methane venting and leakage throughout the US natural gas industry

### Dear Inspector General Elkins:

NC WARN, a nonprofit founded in 1988 in North Carolina, has members across this state who are deeply concerned about the impacts on the climate crisis from methane venting and leakage in natural gas mining, production and distribution. In investigating methane impacts we have come across systematic fraud, waste and abuse by a high-ranking EPA official and possibly others in the data collection, results and process of two of the major studies used by EPA in developing policies and regulation.

NC WARN hereby files this complaint and request for your investigation of allegations we are bringing before you. Based on our extensive review of documentation and direct accounts from a credible whistleblower, we believe there has been a persistent and deliberate cover-up that has prevented the agency from requiring the natural gas industry to make widespread, urgently needed and achievable reductions in methane venting and leakage ("emissions") across the nation's expanding natural gas infrastructure.

Studies relied upon by EPA to develop policy and regulations were scientifically invalid. Several researchers were biased and had direct conflicts of interest. Industry influence may have contributed to the non-disclosure of flaws in the studies and to the resulting cover-up.

For more than two years the whistleblower, engineer Touché Howard, has repeatedly urged various EPA officials to address and resolve technical problems that have led to greatly underestimated methane emissions in natural gas production. To date, these problems have not

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NC WARN Complaint to EPA Inspector General

June 8, 2016

been addressed. When we learned of this, we reached out to Mr. Howard to better understand these problems, which eventually led to this complaint.

The Office of Inspector General (OIG) issued a report on July 25, 2014 that was critical of EPA efforts to reduce methane emissions. That report looked at the natural gas *distribution* sector, in which reductions of emissions could result in a 1% decrease in industry-wide emissions. By contrast, our complaint involves the production sector, which constitutes 82% of total potential emission reductions (EPA-OIG 2014, 17). Thus, underestimating methane emissions from the production sector has a far greater impact on climate, safety and public health than underestimating leakage in the distribution sector.

Due to warnings by the global scientific community about the urgency of making dramatic reductions in greenhouse gas emission, and because methane emissions from the gas industry are now considered by leading researchers to be the largest source of climate-disrupting emissions in the United States, and because methane and toxic air emissions pose an unresolved hazard to both gas industry workers and surrounding communities, we urge you to expedite this investigation to the greatest extent possible.

### **BACKGROUND**

Methane, a greenhouse gas judged by the Intergovernmental Panel on Climate Change to be 100 times more potent than carbon dioxide over a ten-year period in terms of climate impacts, is the dominant component of natural gas. Consequently, there is growing concern that the heat-trapping characteristics of emissions of methane in the natural gas system substantially exceed any climate benefits that might be gained as the electric power industry and others replace coal and oil with natural gas, including fracking gas, also referred to as shale gas.

Routine emissions, via planned venting – both continuous and intermittent – and from unintentional leakage throughout the various sectors of the oil and gas industry infrastructure, have recently been identified as the largest source of greenhouse gas pollution in the US. Such ongoing emissions account for at least 29% of total US methane emissions, and possibly much more, as described below (Vaidyanathan 2015).

The natural gas industry has displayed a persistent interest in downplaying emissions and preventing regulation requiring the industry to either reduce or capture and re-use emissions. The industry has also played both a participatory and funding role in studies of emissions, including those involved in this complaint.

As noted by Dr. Robert Howarth, a leading methane emissions expert from Cornell University, the rapid growth of the US natural gas industry in recent years due to extraction of shale gas has led to increasing concern about the growing levels of methane emissions reported in most studies. A notable exception was a study published in September 2013 by the Environmental Defense Fund (EDF) and the University of Texas at Austin (UT), listed as Allen et al. (2013) in Figure 1 below.

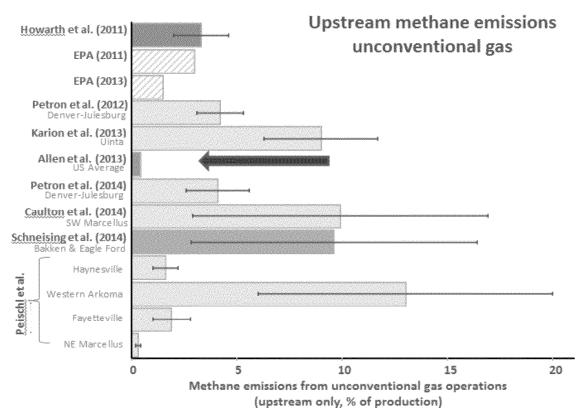


Figure 1. Comparison of methane emission studies across the US, showing the average findings much higher than those from the Allen et al. (2013) study (Howarth 2016, 17, modified).

Due to conflicting data on methane leakage rates, EDF launched a series of 16 studies in 2012 costing \$18 million to look at emissions from the life-cycle of natural gas production, with funding from individuals, foundations (\$12 million), and industry (\$6 million) (Bagley and Song 2015). Oil and gas companies provided 90% of the funding for the Allen et al. (2013) study, which was part of the EDF series and was published in the *Proceedings of the National Academy of Sciences*.

The UT team was led by Dr. David Allen, who also served as Chair of the EPA Science Advisory Board at the time. This study (Allen et al. 2013) reported on emissions from well sites in the production sector and was highly publicized in the news media and disseminated widely by UT team members.

In December of 2014, the UT team published a follow-up study targeting methane emissions from pneumatic devices at production sites (Allen et al. 2014). Pneumatic devices typically rely on natural gas from the site to operate and, as such, vent gas either intermittently or continuously during routine operation. Because of the large number of these devices in use in the production

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sector in the US – approximately 500,000 according to Allen et al. (2014) – they are currently considered by EPA to be the dominant source of methane emissions at production sites.

Unfortunately, both of these studies had significant technical problems that caused underreporting of emissions from production sites, but those problems were not disclosed or acknowledged by the study authors.

Allen et al. (2013) relied on the Bacharach Hi-Flow Sampler (BHFS) for measurements made at chemical injection pumps, equipment leaks, pneumatic controllers and tanks (although tank emission data were not included in the emission inventory for this study). However, since the publication of the 2013 study, it has been demonstrated that sensor failure can cause the BHFS not to switch from its low scale to its high scale, resulting in underreporting of emission rates by orders of magnitude (Howard et al. 2015). Further study then showed that this BHFS sensor failure clearly caused underreporting of emission rates in Allen et al. (2013) (Howard 2015b). See Appendix C for Dr. Allen's comment on Howard (2015b) and Mr. Howard's response to the comment.

The Allen et al. (2014) study of pneumatic devices relied on both the BHFS and Fox flow meters, and this study also underreported emission rates due to an undisclosed problem with the flow meter calibration. Independent tests conducted during that project indicated that one of the two Fox flow meters was underreporting by a factor of three, and that no routine calibrations were in place to discover such problems (Howard 2015a). The study authors did not disclose those independent tests or the full extent of the flow meter calibration problems. As a result, at least half of their emissions measurements may be biased low by a factor of two or more. (See Appendix D.)

In addition, UT collected substantial data on tank emissions during Allen et al. (2013) but did not use it, even though this data set might be one of the most extensive and up-to-date data sets available for tank emissions. It is clear that existing tank models do not work well, and tanks might be the dominant source of methane emissions at well sites, by far. At the same time, all indications are that the BHFS was experiencing widespread sensor failure while used by the UT team to make these measurements, and it seems likely that the UT team would have encountered tank emissions large enough that this sensor failure would be obvious. (See Appendix E.)

These problems were brought to the attention of Dr. Allen, other project participants and multiple EPA officials by engineer Touché Howard. Despite his years of expertise in emissions measuring, the fact that he invented the measuring technology that led to the BHFS and his involvement in the EDF project, Howard's repeated attempts to bring the problems summarized above to the attention of the project's leaders and to other EPA officials – through direct communications and a series of peer-reviewed analyses in publicly available journals – have repeatedly been ignored or misrepresented to date. This is in spite of clear, direct evidence that includes observation of BHFS and Fox flow meter failures by technicians and other project participants.

In fact, problems with the BHFS underreporting emissions had been identified as early as 2012 in a paper co-authored by EPA researcher Eban Thoma (Modrak 2012).

In July 2015, Bacharach, Inc. posted a revised BHFS manual on its website (Bacharach 2015) shortly after a reporter asked the company to comment on the sensor failure (Song 2015). The update recommends daily rather than monthly calibration in the case of mixed gas streams and warns of the possibility of sensor transition failure, recommending some minimal workarounds. The revision does not recommend updating the firmware, nor does it indicate the scale of the problem or offer a meaningful way to prevent it. The question is whether Bacharach's revision was in response to the concerns raised by Mr. Howard or whether they were also notified of the problem by members of the Allen 2013 or 2014 team or other users. As far as we know, Bacharach did not issue a product alert to existing users of the BHFS at the time the manual was revised.

It appears that the goal of the UT team was not to critically examine the problems but to convince EDF and its production committee members that no problems existed. We believe Mr. Howard was specifically prevented from providing input because the UT team knew that he would be able to show that their counterarguments were faulty and the resulting studies scientifically invalid.

The problems Mr. Howard identified have not been openly addressed or corrected, resulting in the failure of the EPA to accurately report methane emissions for more than two years, much less require reductions. Meanwhile, the faulty data and measuring equipment are still being used extensively throughout the natural gas industry worldwide.

Non-disclosure and cover-up could have widespread implications. The BHFS has been used at all stages of natural gas processing, transmission, storage and distribution to determine methane emissions (see Figure 2). It is also one of the devices approved by EPA for mandatory reporting of methane emissions under Subpart W of the Greenhouse Gas Reporting Program (EPA 2016b).

Because EPA, academic and industry personnel have ignored or misrepresented these problems instead of addressing them with Mr. Howard in a professional manner, methane emissions remain poorly quantified, although it seems very likely that they are much higher than estimated by EPA. For example, a 2016 EDF study (Lyon 2016) found methane leakage rates 90% higher than original estimates, with 90% of the leaks coming from tanks (McKenna 2016). Current scientific consensus, as shown in Figure 1, is that the methane emissions from natural gas production and distribution are much higher than indicated by the invalid Allen studies.

### SUMMARY OF SPECIFIC ALLEGATIONS DETAILED IN APPENDIX A

Since being made aware of the flaws in Allen et al. (2013) and Allen et al. (2014), Dr. Allen misused his authority, gave false or misleading information, provided inadequate documentation and delayed producing requested documentation, thus minimizing and failing to disclose the serious malfunctioning of the BHFS and Fox flow meters and the consequent effect on test results.

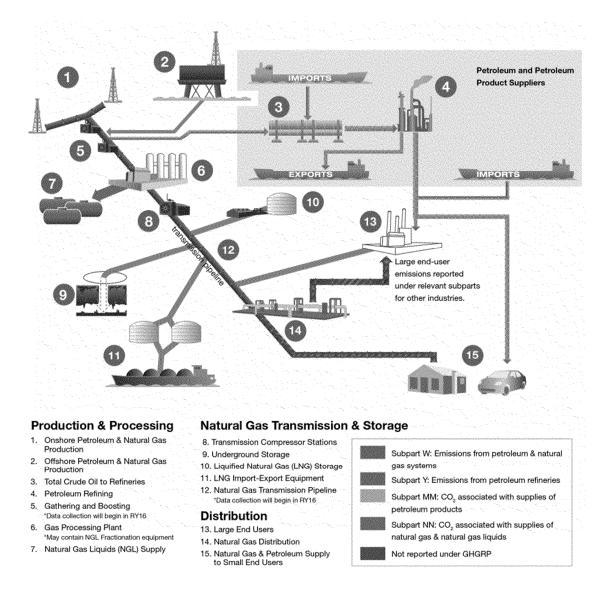


Figure 2. Natural gas production sectors in which the Bacharach Hi-Flow Sampler (BHFS) is used. Diagram source: https://www.epa.gov/ghgreporting/ghgrp-and-oil-and-gas-industry.

Dr. Allen knew or should have known that the malfunctioning BHFS resulted in invalid data that should not have been used for Allen et al. (2013). Dr. Allen knew or should have known that the malfunctioning BHFS, as well as problems with the Fox flow meters, resulted in invalid data being published in Allen et al. (2014). Allen misrepresented to Mr. Howard that his concerns would be addressed. In refusing to address the issue of invalid data, and refusing to communicate further with Mr. Howard, Dr. Allen's actions resulted in delay and misuse of EPA funds.

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Dr. Allen, as principal researcher, had a duty to investigate and disclose to the EPA, EDF and other researchers issues that indicated severe problems with the BHFS, the tank data and the pneumatic device study (Allen et al. 2014).

The confidential rebuttal memo (undated, see Appendix B) that Dr. Allen distributed to members of the production team was intended to mislead the EDF production committees about the significance and scope of the problems with the BHFS.

Dr. Allen and the UT team further misled the editor and readers of *Environmental Science & Technology* in Dr. Allen's response to Howard's Comment on Allen et al. (2014).

In March of 2014, Dr. Allen failed to disclose to EPA, industry, EDF and Bacharach, Inc. that the BHFS sensor failure had been clearly demonstrated, and that problems with the BHFS appeared to have been only partially resolved with updated firmware and frequent calibrations.

Dr. Allen, as chair of the EPA Science Advisory Board from 2012 to 2014, was a paid Special Government Employee. As such, he had the additional duty to fully divulge his biases toward industry and his direct conflicts of interest. His disclosure statements in the Allen et al. (2013, 17768) and Allen et al. (2014, 639) studies show his research and consulting have long been funded by the oil and gas industry, bringing the validity of his studies further into question.

### RAMIFICATIONS FOR CLIMATE, SAFETY, HEALTH

It has been demonstrated that sensor failure can cause the BHFS to underreport leak rates and other emission rates by orders of magnitude. Accurate sampling and monitoring by Dr. Allen and the UT team would have given EPA a fuller understanding of the devastating impacts of methane venting and leakage. Because of this failure, EPA funds have been wasted, fraud has been committed, and improper and unlawful actions have been taken. More important, the scientific basis for properly regulating methane emissions from the natural gas industry, and the resulting impact on the climate crisis, have been put back nearly three years.

The Allen studies are high-profile studies that have been widely cited (197 times as of April 2016) and presented before White House and Congressional staff and, as such, have given policy makers and the public an incorrect view of methane emissions from production sites. Specifically, policy makers may underestimate the impact of natural gas use on the climate and on public health (from toxic air emissions), and thus fail to take action to guard against these problems. In some cases (e.g. Denton, TX) state legislatures have overridden local legislation enacted to address the concerns of citizens based on a misguided understanding of methane impacts.

Since 2012, the attorneys general of seven states, led by New York Attorney General Eric T. Schneiderman, have been pressing EPA to regulate methane emissions not just from new natural gas facilities but also from existing ones. In April 2016 a coalition of 12 US mayors asked President

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Obama to address the issue of methane leaking from existing oil and gas production sites (see Appendix F).

The flaws in the Allen studies have enormous environmental, health, and safety implications. The BHFS is currently the standard instrument in the natural gas industry worldwide for measuring methane emissions. The analysis by Mr. Howard (2015b) indicates that BHFS sensor failure could occur in all segments of the natural gas industry, not just in production. Consequently, sensor failure in the BHFS may cause both underreporting of methane emissions as well as emissions of heavier hydrocarbons and air toxics, resulting in the underestimation of the health effects from air emissions at oil and natural gas facilities. This problem may have affected other research and government programs, causing methane emission inventories to be biased low, including the inventories compiled by the US EPA Subpart W Greenhouse Gas Reporting program (US CFR 2014), the American Carbon Registry (ACR 2010), and the United Nations Clean Development Mechanism (UN CDM 2009).

Most important, however, the BHFS is also used to prioritize the repair of natural gas leaks, and if a large leak were not repaired because the BHFS underestimated it, this could lead to catastrophic component failure and/or explosion.

### A HIGHLY CREDIBLE WHISTLEBLOWER

Touché Howard's education and unique background make him an extremely credible whistleblower. He holds a B.S. in Chemical Engineering, and an M.S. in Environmental Engineering specializing in air emissions and transport, and he has over 25 years of experience measuring methane at natural gas production sites around the world.

Mr. Howard is the inventor of the Hi-Flow Sampler (US Patent RE37,403), a device to measure natural gas leaks that is approved by the EPA and is used by the natural gas industry worldwide. He developed the Hi-Flow Sampler in the early 1990s, assigning the patent to the Gas Research Institute in 2003. Mr. Howard did not participate in development of the commercial version – the Bacharach Hi-Flow Sampler or BHFS – and does not own any rights to the BHFS, nor has he ever financially benefitted from sales of the BHFS, which cost approximately \$20,000 each, with about 500 in use.

Mr. Howard has served as a project manager and trainer for fugitive emission measurement and management programs since 1989 at over 500 natural gas facilities. He recently provided instrumentation, training, field measurements, and analysis for a nationwide methane emissions measurement program focused on above- and below-ground leakage from natural gas distribution systems. Mr. Howard has published over 20 papers on topics including methane and other emissions from natural gas and oil production facilities, including a 2015 study by Brian K. Lamb, Touché Howard and others that is used by the EPA in its April 2016 *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014* (EPA 2016a, 3-80).

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Mr. Howard has gained the respect of colleagues across the field and of leading researchers, for example, Dr. Robert Howarth of Cornell University, a leading researcher of methane emissions and their impacts on climate change. (See Dr. Howarth's letter endorsing Mr. Howard's work, Appendix G.)

Perhaps most salient to this complaint is that, in addition to EPA's reliance on Mr. Howard's expertise, EDF was well aware of his credentials because his instruments, training, field measurements, and analysis were being used for the Washington State University study of methane emissions from natural gas distribution systems, which EDF also sponsored. Dr. Allen initially relied significantly on Mr. Howard, recognizing that Mr. Howard's expertise in emission measurements, particularly with high flow sampling technology, exceeded that of the UT team – until he identified problems with their high-profile studies. (See Attachment H, Vita of Touché Howard.)

### **INDUSTRY INVOLVEMENT & POSTURE**

The Energy Policy Act of 2005 exempted hydraulic fracturing ("fracking") from federal clean air and clean water rules (Song 2016). Emissions factors were developed in the early 1990s and need to be updated to reflect the increase in fracked wells (Song and Bagley 2015).

Indeed, until May 12, 2016, when the EPA released its final rule on emission standards for new oil and gas wells and well-site equipment (EPA 2016), there was no federal regulation and very little state regulation of methane leakage and venting from natural gas production. The EPA has yet to release rules for existing wells, so methane emissions from 75% of oil and gas equipment are still not regulated.

Yet the gas industry is digging in its heels and vowing to fight the new EPA rules, complaining the rules are an economic burden (Davenport 2016). Unfortunately, this fight will be waged using faulty data from the scientifically invalid UT studies. Even more concerning, those data were produced by scientists with a probable bias, if not a direct conflict of interest, due to their prior associations with the industry – see disclosures at Allen et al. (2013) and Allen et al. (2014). Ninety percent of the funding for Dr. Allen's 2013 study came from the oil and gas industry.

Reliance on the Allen studies has allowed the oil and gas industry to continue to claim that emissions are low and that, as a result, no regulation is needed. The American Petroleum Institute (API) hailed the conclusions of Allen et al. (2013) as "proving" that emissions are low (Wines 2013), with other industry groups touting "exceedingly low leakage rates," and claiming that, despite dramatic increases in US natural gas production since 2005, methane emissions from natural gas production have fallen 38% since 2005 (Brown 2015).

Comments submitted by API on EPA's draft *Inventory of U.S. Greenhouse Gas Emissions and Sinks:* 1990-2014 support the findings of Allen et al. (2013) and Allen et al. (2014), minimize the concerns brought up by Howard (2015b) and support use of the BHFS, noting that "the Hi-Flow instrument

is one of a very few existing devices for cost-effectively quantifying natural gas emissions from fugitive and venting at the emission source" (API 2016).

Industry also claims that emissions from shale basins (Brown 2014) and natural gas extraction are down significantly (Dyer 2016) thanks to the findings of the flawed Allen studies. Even more troublesome, the industry has cited Allen et al. (2013) as proof of far lower leakage rates, claiming that spiking methane emissions are due to wetlands and agriculture, and that natural gas will actually solve the climate problem (Brown 2016).

In response to an EPA rule proposed in September 2015 (Federal Register 2015), global oil and gas law firm Jones Day asserts that regulations are not needed, and complains about rules covering compressors, pneumatics and storage tanks, also objecting to the proposed requirement that leaks be repaired within 15 days. Jones Day and oil and gas law firm Bracewell (Snyder 2016) each assert that the cost to capture emissions could exceed the direct monetary value of the recovered natural gas (Jones Day 2015).

### **CONCLUSION**

Dr. Allen was Chair of the EPA Science Advisory Board during the period addressed in this complaint. EPA has relied upon Dr. Allen, so he had a special obligation to address the flaws in his studies and fully disclose this and known problems with the BHFS to EPA policy makers. The BHFS is an EPA-approved instrument and is currently the standard instrument in the natural gas industry worldwide for measuring methane emissions from venting and leakage. Although upgrading its firmware may reduce sensor failure, it does not eliminate it, and it is likely that most BHFS's in use have older firmware more susceptible to sensor failure. The presence of such a problem that can result in large leaks being reported as an order of magnitude smaller than they actually are presents a frightening safety and public health issue and an abject failure by EPA to help stem global climate disruption.

The OIG is tasked with investigating claims of fraud, waste, and abuse. The above summary and attached exhibits demonstrate clear examples of fraud relating to the studies conducted on EPA's behalf, studies EPA has relied upon to prepare rules, guidance documents, and emission standards. EPA has wasted its funds by expending countless hours following up on the flawed studies. There is a clear pattern of abuse of process and conflict of interest in the data collection, preparation, and dissemination of the Allen studies. Too much was covered up and hidden from scientific scrutiny and EPA review.

The OIG is further tasked with investigating complaints of EPA-related criminal activity. In this case, the EPA OIG is required to investigate fraud and false statements pursuant to 18 U.S.C. § 1001.

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THEREFORE, NC WARN requests the following:

- 1. The OIG should conduct an expedited investigation of the allegations in this complaint;
- 2. The OIG should request a retraction of the Allen et al. (2013) and Allen et al. (2014) studies, with a resulting reexamination by EPA of all policies, regulations, technical documents and international treaties that have relied on these studies;
- 3. The OIG should require EPA to conduct a complete (and scientifically valid) study to accurately quantify methane venting and leakage throughout the natural gas production and distribution system; and
- 4. The OIG should investigate the EPA's use of researchers who have industry bias and direct conflicts of interest.

Moreover, because of the extreme urgency of the climate crisis and the significant climate impact of methane venting and leakage in the natural gas industry, and because nearly three years have been lost as a result of the actions outlined in this complaint, we recommend these immediate policy changes as a way of redressing the damage that has been done:

- 1. EPA should institute a zero emission goal for methane;
- 2. EPA should initiate a full regimen for oversight, testing and remediation of methane emissions in the natural gas industry; and
- 3. EPA should take into account the global warming potential of methane emissions over a 20-year (not 100-year) timeframe.

We look forward to cooperating with you to determine the extent and remedy of this issue. In addition to the appendices included herein, we have other correspondence, studies, and an extensive timeline of events that will be made available upon request.

Sincerely.

Jim Warren

Executive Director

cc: EPA Administrator Gina McCarthy UT Austin President Gregory L. Fenves

EDF President Fred Krupp

Air Waner

Dr. David Allen

June 8, 2016

### **VERIFICATION**

I, Touché Howard, verify that the contents of the above Complaint submitted to the U.S. Environmental Protection Agency's Office of Inspector General are true to the best of my knowledge, except those matters stated on information and belief, and as to those matters, I believe them to be true.

Harry McVern Touché Howard

Date: JUNE 1, 2016

Sworn to and subscribed before me this the  $\frac{15!}{10!}$  day of  $\frac{1}{10!}$  , 2016.

Notary Public

My Commission expires: 1/6/2018

ANNA HENRY
NOTARY PUBLIC, NORTH CAROLINA
WAKE COUNTY
MY COMMISSION EXPIRES

June 8, 2016

### **VERIFICATION**

I, Jim Warren, verify that the contents of the above Complaint submitted to the U.S. Environmental Protection Agency's Office of Inspector General are true to the best of my knowledge, except those matters stated on information and belief, and as to those matters, I believe them to be true.

Jim Warren

Date: 6/1/16

Sworn to and subscribed before me this the  $\frac{19t}{2}$  day of  $\frac{1000}{2}$ , 2016.

Notary Public

My Commission expires: 1/6/2018

ANNA HENRY
NOTARY PUBLIC, NORTH CAROLINA
WAKE COUNTY
MY COMMISSION EXPIRES

### **APPENDIX A. Allegations**

### A. Scope of Review

The EPA provides the following definitions and examples of Fraud, Waste and Abuse (EPA 2016c):

Fraud: a false representation about a material fact, any intentional deception designed to unlawfully deprive the United States or EPA of something of value or to secure for an individual a benefit, privilege, allowance or consideration to which he or she is not entitled, inadequate or missing documentation, delays in producing requested documentation, false or misleading information, lack of communication and/or support for ethical standards by management.

**Waste**: involves the taxpayers not receiving a reasonable value for money in connection with any government-funded activities due to inappropriate act or omission. Most waste does not involve a violation of law, but relates primarily to mismanagement, inappropriate actions, and inadequate oversight.

**Abuse**: behavior that is deficient or improper, misuse of authority, misusing the official's position for personal gain, and conflict of interest. Abuse does not necessarily involve fraud or violations of laws, regulations, or provisions of a contract.

The EPA OIG also reviews complaints of EPA-related criminal activity. In this case, the EPA OIG is required to investigate fraud and false statements pursuant to 18 U.S.C. § 1001:

- (a) Except as otherwise provided in this section, whoever, in any matter within the jurisdiction of the executive, legislative, or judicial branch of the Government of the United States, knowingly and willfully—
  - (1) falsifies, conceals, or covers up by any trick, scheme, or device a material fact;
  - (2) makes any materially false, fictitious, or fraudulent statement or representation; or
- (3) makes or uses any false writing or document knowing the same to contain any materially false, fictitious, or fraudulent statement or entry; shall be fined under this title, imprisoned not more than 5 years or, if the offense involves international or domestic terrorism (as defined in section 2331), imprisoned not more than 8 years, or both. If the matter relates to an offense under chapter 109A, 109B, 110, or 117, or section 1591, then the term of imprisonment imposed under this

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section shall be not more than 8 years.

### B. List of Specific Allegations

- a. Phase I Study (Allen et al. 2013): The principal researcher of the University of Texas at Austin studies, Dr. David Allen, who was EPA Science Advisory Board Chair from 2012 to 2014, misused his authority, gave false or misleading information, provided inadequate documentation and delayed producing requested documentation, thus minimizing and failing to disclose to the EDF Production Group (EDF staff scientists and managers, the Technical Working Group, representatives from project sponsors, the Steering Committee and the Science Advisory Committee) the serious malfunctioning of the Bacharach Hi-Flow Sampler (BHFS), the tool used to measure methane leakage in Allen et al. (2013). Dr. Allen knew or should have known that the malfunctioning BHFS resulted in invalid data that should not have been used for the Allen et al. (2013) results.
  - i. In October 2013, Dr. Allen, who led the UT team for the Phase I study that directly measured methane leakage in the natural gas production sector, was informed by Mr. Howard of the fact that the main measurement tool being used for the Phase I study (Allen et al. 2013), the BHFS, was malfunctioning. Since the BHFS is a widely used tool to measure natural gas methane emissions, this means that invalid results have widespread, profound implications. Rather than act on this information by disclosing it to other research participants, Dr. Allen misused his authority, and gave false or misleading information to the EDF Production Group between October 2013 and January 2014, minimizing Mr. Howard's concerns.
  - ii. Between November 2013 and January 2014, Dr. Allen knowingly misrepresented to Mr. Howard that Dr. Allen would stop the next phase of the research, Phase II (Allen et al. 2014), due to Mr. Howard's concerns about the BHFS malfunctioning. Dr. Allen misused his authority by falsely telling Mr. Howard that Dr. Allen would involve Mr. Howard in quality assurance for Phase II, which focused on emissions from pneumatic devices using the BHFS (as well as Fox flow meters).
  - iii. This delay also resulted in Mr. Howard's inability to respond publicly in a scientific journal, the Proceedings of the National Academy of Sciences (PNAS), about how problems with the BHFS might affect Allen et al. (2013). Dr. Allen's knowing misrepresentations to Mr. Howard that they would collaborate on this issue resulted in the expiration of the three-month window (October to December 2013) that Mr. Howard had to respond publicly in the journal PNAS to Dr. Allen and the UT team on the malfunctioning of the BHFS.

- iv. Therefore, these delays and intentional misrepresentations resulted in a misuse of funds by the EPA, since Dr. Allen, as Chair of the EPA Science Advisory Board, knew or should have known that the malfunctioning of the BHFS resulted in bad data for Allen et al. (2013). These intentional misrepresentations raise serious questions about the scientific validity of the findings in Allen et al. (2013) and demonstrate a clear conflict of interest in Dr. Allen's publication of data he knew or should have known to be false. As an EPA employee at the time, Dr. Allen had a clear duty to investigate underreporting of the BHFS.
- b. Phase II Study (Allen et al. 2014, pneumatics): Dr. Allen misused his authority, gave false or misleading information, provided inadequate documentation and delayed producing requested documentation by minimizing and failing to disclose to the EDF Production Group the serious malfunctioning of the Bacharach Hi-Flow Sampler (BHFS). Dr. Allen knew or should have known that the malfunctioning BHFS, as well as problems with the Fox flow meters, resulted in invalid data. Dr. Allen and the UT team misrepresented to Mr. Howard that his concerns would be addressed. In refusing to address the issue of invalid data, and refusing to communicate further with Mr. Howard, Dr. Allen's actions resulted in delay and misuse of EPA funds.
  - i. In March 2014, Mr. Howard and industry colleagues conducted field tests of the University of Texas (UT) BHFS and Fox flow meters on pneumatic devices. (These field tests were not part of Phase I or Phase II UT studies, but were done separately during the Phase II study timeframe as a result of the concerns of Mr. Howard and UT team members about the malfunctioning of the BHFS.) Pneumatic devices deserve special attention as the EPA reports there were 977,000 pneumatic devices used in US natural gas production in 2012.
  - ii. In March 2014, in connection with these field tests, Mr. Howard made an agreement with members of the UT team to present a joint statement to the EDF production committees about the problems with both the BHFS and Fox flow meters, and how these problems may have affected research results. However, rather than work on a joint statement, the UT team immediately presented the March 2014 test results of the BHFS without Mr. Howard's knowledge or input.<sup>1</sup> (However, whether problems with the Fox flow meter were disclosed in that meeting is unknown.)

<sup>&</sup>lt;sup>1</sup> These test results from the March 2014 field tests were included in both Howard et al. (2015) and How ard (2015b).

- iii. Dr. Allen then refused to communicate further with Mr. Howard, resulting in a further delay of the investigation because Mr. Howard assumed he was still collaborating with the UT team on Phases I and II when, in fact, the UT team had no intention of working with him. By preventing Mr. Howard's input, the UT team was able to minimize the problems with the BHFS to all team members, including the EDF Production Group.
- iv. The problems with the Phase II data set, which Mr. Howard made clear to the UT team in emails (available upon request), included:
  - 1. No routine calibration on the Fox flow meters while in the field.
  - One Fox flow meter (out of two that were used in the study) was reading far too low, and without routine calibrations there was no way to determine if the other meter also had problems.
- v. Matt Harrison, a member of the UT team, told Mr. Howard in an email dated 6/23/14 (available upon request) that he was "taking a big scientific risk" in publishing his results criticizing Allen et al. (2013) without first seeing the Phase II data. Dr. Allen had previously asserted that if Mr. Howard completed a Non-Disclosure Agreement (NDA), he would be able to see the Phase II data. However, even after Mr. Howard completed an NDA, Dr. Allen withheld the data he had promised Mr. Howard. (Detailed timeline available).
- vi. Because the UT team refused to disclose the Phase II data, Mr. Howard had no way to evaluate the UT team's assertion that the Phase II results confirmed Dr. Allen's conclusions that problems with the BHFS did not affect the Phase I results. The Phase II data were never made available to Mr. Howard until they were published six months later, in late 2014 (Allen et al. 2014), and the results showed that Mr. Howard's analysis was correct.
- vii. Dr. Allen published the Allen et al. (2014) pneumatic data but did not disclose the tests that Mr. Howard conducted in March 2014 showing that the performance of one of the Fox flow meters used was far worse than indicated in their supplemental information. Mr. Howard published

<sup>&</sup>lt;sup>2</sup> Mr. Howard reviewed the meter problems in an email exchange with Matt Harrison (2014-03-21 Matt Harri son) in which Mr. Harrison suggests Mr. Howard take the reference to the meter out of the joint statement. Ms. Carrie Reese with Pioneer Natural Resources confirmed she had notified EDF of the meter problem (2014-05-19 C arrie Reese). After the study was published, Mr. Howard r eviewed meter problems with EDF in detail; EDF init ially said it would investigate but then stopped responding (2014 -12-12 Steve Hamburg). All emails available upon re quest.

- a comment on Allen et al. (2014) (Howard 2015a) and Dr. Allen published a response to the comment (Allen 2015).
- viii. The UT team failed to disclose that independent testing of their Fox flow meters demonstrated that at least one meter was underreporting far worse than the authors indicated. This failure alone necessitates the retraction of Allen et al. (2014). However, the UT team should provide the complete data set to EPA, the editor of the *Environmental Science & Technology* journal and the EDF production science advisory committee in order to assist with investigating whether the UT team took other actions to hide the poor performance of these flow meters. For instance, it is important to determine whether the UT team: did immediate follow-up testing after Mr. Howard demonstrated the problems with one Fox flow meter but did not disclose this; cleaned or otherwise tried to improve the performance of the faulty Fox flow meter before the end-of-project calibration test was conducted; or manipulated data points to create a location in the data set where the start of the meter problem could be artificially identified so no data would have to be eliminated.
- ix. Therefore, the delays, knowing misrepresentations, and lack of communication in addressing problems with the Phase II data have resulted in a knowing misuse of EPA resources by Dr. Allen, as Chair of the EPA Science Advisory Board and a paid employee of EPA.
- c. The UT team knew or should have known the BHFS measurements of tanks were underreporting emissions.
  - i. The UT team knew or should have known its BHFS was underreporting tank data in Phase I (Allen et al. 2013). As part of that study, 124 tanks were measured. These data were not used for the Allen et al. (2013) inventory calculations, though they were published on the UT website. This data set is extremely important as it is one of the most up-to-date, comprehensive data sets of tank emissions available. Tank emissions are an enormous source of methane emissions at production sites, and thus this data set, if accurate, could have provided significant insight into total methane emissions from the production sector (McKenna 2016).
  - ii. A key question is whether or not the UT team recognized this data set was faulty but did not disclose this fact. (Further discussion is provided in Appendix E). If the UT team knew the tank data were faulty, the following points must be considered:

- That Dr. Allen published tank data on the UT website that he knew were invalid without any notation that they might be faulty;
- That Dr. Allen was aware that the BHFS was underreporting data for tank emissions but did not report this to EPA, even though he was chair of the EPA Science Advisory Board and the BHFS is approved by EPA to make Subpart W measurements of tanks in the transmission, storage and processing sectors; and
- 3. That Dr. Allen knew, when Mr. Howard first reported his concerns about the BHFS sensor failure in late 2013, that the BHFS was underreporting tank emissions, so that Dr. Allen should have acted on Mr. Howard's concerns immediately.
- iii. Therefore, the delays, use of false or misleading information, knowing misrepresentations and lack of communication in addressing problems with the tank data have resulted in a knowing misuse of EPA resources.
- d. Dr. Allen, as principal researcher, had a duty to investigate and disclose to the EPA issues that indicated severe problems with the BHFS, the tank data and the Phase II pneumatic device study.
  - i. As chair of the EPA Science Advisory Board, Dr. Allen had a legal, ethical and moral duty to investigate and disclose issues in his research that indicated such a severe problem with the BHFS, a widely-used instrument approved by EPA for Subpart W Greenhouse Gas emission measurements (EPA 2016b), with enormous environmental, health and safety implications, including:
    - the impact on climate of underreported methane emissions due to BHFS sensor failure in Allen et al. (2013) as well as on other GHG inventories such as EPA Subpart W, since such underreporting could adversely affect public policy;
    - 2. the impact on community health from underestimates of air toxic emissions inventories that may also be derived from inventories such as those listed in (1) above; sites with heavier hydrocarbons have both the greatest air toxics impact and the greatest likelihood of underreporting due to BHFS, and this underreporting could prevent policy makers from taking adequate action to protect the health of communities near oil and gas facilities; and
    - 3. the impact on safety and health resulting from significant leaks going unidentified and unrepaired due to BHFS sensor

failure, since large leaks could lead to catastrophic failure as well as contribute significantly to air pollution impact on nearby communities.

- ii. Dr. Allen took specific actions to delay the BHFS underreporting investigation and disclosure, and to discredit the valid concerns of Mr. Howard, including:
  - repeatedly leading Mr. Howard to believe that the UT team would collaborate with him to investigate and disclose the BHFS sensor failure;
  - 2. leading EDF staff and committees to believe that he would address the issue of BHFS sensor failure with Mr. Howard while actually refusing to communicate with Mr. Howard; and
  - disseminating arguments against the effect of BHFS sensor failure on the Phase I data set that Dr. Allen knew to be false in a confidential memo (Appendix B) without giving Mr. Howard any notification or opportunity to respond.
- iii. Comments sent to EPA by Dr. Allen on leaks (Allen 2014a) and pneumatics (Allen 2014b) submitted in June 2014 included data Dr. Allen knew to be false and misleading.
- iv. Therefore, the delays, knowing misrepresentations and lack of communication in addressing problems with the BHFS and Fox flow meters resulted in a knowing misuse of EPA resources.
- e. The confidential, undated rebuttal memo (Appendix B) that Dr. Allen distributed to members of the production team was intended to mislead the EDF production committees about the significance and scope of the problems with the BHFS.
  - i. Between July and October 2014, Dr. Allen wrote a confidential rebuttal memo that was distributed to EDF and its production committees (academic and industry representatives), without Mr. Howard's knowledge or input. This rebuttal memo argued that Mr. Howard was wrong about the BHFS sensor failure's effect on the Allen et al. (2013) study.
  - ii. This rebuttal memo was not released to the public and was only obtained through a Freedom of Information Act request.

- iii. Mr. Howard was never allowed to speak with members of the EDF production committees at any time, even after the rebuttal memo came to light, so that the issue of BHFS failure was never addressed.
- iv. Dr. Allen's rebuttal failed to disclose that the UT BHFS tested in March 2014 had a newer version of firmware than when used in Phase I and that Heath Consultants, distributor of the BHFS as well as the company with the most experience with the BHFS, had reported that new firmware had addressed *some* of the problems with the BHFS underreporting of methane leaks.
- v. Therefore, Dr. Allen knowingly misrepresented, and failed to disclose material information he knew or should have known to be incorrect in the rebuttal memo, resulting in a misuse of EPA resources.
- f. Dr. Allen and the UT team also misled the editor and readers of Environmental Science & Technology in Dr. Allen's response (Allen 2015) to Mr. Howard's comment (Howard 2015a) on Allen et al. (2014).
  - i. Dr. Allen failed to disclose that the UT BHFS tested in the UT laboratory and in the March of 2014 field testing had a newer version of firmware than when used in Phase I and that Heath Consultants stated that new firmware had addressed only some of the problems with the BHFS.
  - ii. Dr. Allen asserted that the March 2014 field tests conducted by Mr. Howard in the presence of members of the UT team were not done correctly and that proper protocols were not followed.
  - iii. Therefore, Dr. Allen knowingly misrepresented and failed to disclose material information he knew or should have known about the updated firmware and its effect on the problems with the BHFS, resulting in a misuse of EPA resources.
- g. In March 2014, Dr. Allen failed to disclose to EPA, industry and Bacharach, Inc. that BHFS sensor failure had been clearly demonstrated, and that problems with the BHFS appeared to have been only partially resolved with updated firmware and frequent calibrations.
  - Dr. Allen knew or should have known that his efforts to prevent investigation and disclosure of the BHFS sensor failure would likely result in invalid study results.

- ii. Consequently, at least an additional two years of EPA Subpart W emissions data may have been underreported. In addition, community health and worker safety may have been needlessly impacted.
- iii. Therefore, Dr. Allen knowingly misrepresented, and failed to disclose material information he knew or should have known to be incorrect when he asserted that updated firmware and more frequent calibrations resolved the problems with the BHFS, resulting in a misuse of EPA resources.
- h. As demonstrated in his disclosure statements in Allen et al. (2013) and Allen et al. (2014), Dr. Allen has a long history of consulting for industry and leading industry-controlled and industry-funded studies. His biases, and direct conflict of interest, may have contributed to his failure to disclose malfunctioning tools and faulty data.

### APPENDIX B. Discussion of Confidential Allen Memo

### Statement by Touché Howard

In October of 2014, while addressing my concerns about sensor failure in the Bacharach Hi-Flow Sampler (BHFS) via conference call with the American Petroleum Institute, one of the participants said, "I don't even know why we're having this call. I have a memo from David Allen saying this isn't a problem." When I later asked why I hadn't been shown this memo, Matt Harrison of URS Corporation said that it was confidential but that it focused on regional differences and also the Phase II results (Allen et al. (2014), at that time not yet published). I was very surprised to learn of the existence of this memo, since I was given no opportunity to respond to it or to understand its contents, and it was clear that it minimized the problem of BHFS sensor failure. Even after publication of Allen et al. (2014), after which the contents of the memo would no longer be confidential due to Phase II data, my repeated requests to EDF and Dr. Allen to see this memo were ignored.

The memo ("Analysis of HiFlow Sampler Cross-Over Performance in University of Texas Methane Studies") was eventually released under a Texas Open Records Act request in November of 2015 (although I only discovered that in April of 2016) and is attached at the end of this appendix. Unfortunately, the arguments made in this memo are not only faulty, but also ones that Dr. Allen and his colleagues had reason to know were incorrect. Consequently, it appears that Dr. Allen specifically tried to mislead EDF and its production committees about the severity of the BHFS failure issue and its effect on Allen et al. (2013). The arguments made in the memo are discussed below.

- 1) The memo states that laboratory testing, done in the fall of 2013, showed that the UT BHFS did not exhibit sensor failure. However:
  - a. All of this testing was done after the UT BHFS firmware was upgraded, but the memo excludes that point and makes no mention anywhere that Heath Consultants technicians had reported that upgraded firmware had dramatically improved the performance of BHFS's that were known to be underreporting.
  - b. The UT person in charge of laboratory testing reported that they calibrated their BHFS before every test, which was not the protocol used in Allen et al. (2013) as reported by a URS field technician. Recent calibration was seen to eliminate the sensor failure on the UT instrument (which had new firmware) during the March 2014 field testing.
- 2) The memo states that the March 2014 field testing I conducted showed only one failure, and that failure was not representative because their protocol was to calibrate any time the instrument was turned on and the test emission rate of 60 scfh (standard cubic feet per hour) was greater than 98% of the Allen et al. (2014) emission rates. However:
  - a. Again, they do not disclose that the March 2014 testing was conducted on samplers that had their firmware upgraded, and that this upgrade was reported

- to dramatically improve the performance of BHFS's that were underreporting leak rates.
- b. During the March 2014 field tests, I was given the UT BHFS to test after the UT team had conducted a bump test (as opposed to a full calibration). The UT team never suggested prior to the testing that it should be fully calibrated and only performed such a calibration after the sensor failure occurred. Another field technician from URS specifically stated that they didn't routinely calibrate during Allen et al. (2013) (Phase I) or during the work he had done on Allen et al. (2014) (Phase II, ongoing at the time of these tests). This was corroborated by the fact that the UT BHFS internal log indicated that it had not been calibrated for two weeks prior to these tests, even though it was being used for the UT Phase II program during that time.
- c. The complaint that the test flow rate was atypical because it was greater than 98% of the sources measured during Phase II is very misleading, as the UT team knows. The test flow rate of 60 scfh is actually a relatively low emission rate that the BHFS might need to measure in any routine field measurement program. Moreover, as both Allen et al. (2013) and Allen et al. (2014) point out and as has been shown in other studies, the large emitters are the most important. The UT team knows that it is critical that the BHFS be able to accurately measure the larger emission rates. Results from the 2% of pneumatic devices measured in Allen et al. (2014) (Phase II) that were larger than the test flow rate of 60 scfh accounted for 31% of the total emission rate measured in that work. In the Fort Worth study (ERG 2011), 10% of all the sources measured by BHFS were >60 scfh and made up 63% of the total emission rate, and several sources were observed to be at the top capacity of the BHFS. Sources >0.4 scfm (24 scfh, the approximate emission rate requiring the BHFS to transition to its high scale) in the Fort Worth study made up 20% of all sources but 81% of the total emission rate. BHFS sensor failure does not appear to have been prevalent during that study (as discussed in Howard et al. 2015) but this distribution of emission rates shows how critical it is for the BHFS to be able to measure larger emission rates. If BHFS sensor failure had occurred in the Fort Worth study and caused underreporting of all sources >0.4 scfm (24 scfh), then the reported measurements would have been too low by a factor of five.
- 3) The memo states that analysis of Infrared (IR) Camera scans did not indicate that any large leakage had been missed. However:
  - a. It is not possible to accurately quantify emissions using the IR camera due to variations in camera performance and dilution of the source due to wind speed and turbulence changes. During the Fort Worth study (ERG 2011) the daily IR camera performance checks indicated over an order of magnitude variation in how well a known source could be detected.

- 4) The memo states that the average of pneumatic device emission measurements Allen et al. (2013) made by the BHFS are greater than in Allen et al. (2014), made by Fox flow meters, and then goes on to state that if BHFS sensor failure had caused underreporting in the 2013 study, the 2013 emission rates would have been lower than 2014. However:
  - a. The 2013 pneumatic measurements made by BHFS inadvertently focused almost exclusively on devices that were emitting (over 95% were emitting) whereas the 2014 pneumatic measurements were comprehensive (all pneumatics were measured and the frequency of emitting devices is less than 25%). If both measurement methods were accurate, this would cause the 2013 average emission rates to be 4 to 5 times greater than 2014. Additionally, as discussed in Howard (2015a), other problems may have biased the 2014 measurements low, such as resetting pneumatics by installing flow meters and at least one flow meter with a dirty sensor.
  - b. Although the memo (in Figure 3) presents a comparison of 2013 to 2014 emission rate versus concentration, it does not explain the significance of the dramatic difference in the patterns between the two graphs which I had repeatedly predicted would exist. The 2014 data, measured by Fox flow meter instead of BHFS, does in fact show that high emitters occur at sites with lower methane content; these are notably absent in the 2013 data measured by BHFS. This is particularly significant because these were graphs generated by the UT team (as opposed to myself), they were aware of the significance in the difference of the patterns, but do not discuss this difference at all in the memo.

Unfortunately, all of the arguments in the memo are so flawed that it appears that the goal of the UT team was not to critically examine the issue but to convince EDF and its production committee members that no problems existed. These committee members would not have had the specific expertise needed to evaluate these arguments, but if I had been allowed to rebut these arguments, I would have been able to prevent the committee members from being misled. It seems likely that I was specifically prevented from providing input because the UT team knew that I would be able to show that their arguments were completely invalid.

## Analysis of HiFlow® Sampler Cross-Over Performance in University of Texas Methane Studies

David Allen', David Sullivan', Daniel Zavala-Araiza', Matt Harrison2

Allen et al. (2013) provided unprecedented direct measurements of methane emissions from a variety of natural gas production equipment in the United States. Some investigators have recently challenged the validity of the data collected in Allen et al. (2013) based on the assertion of a cross-over malfunction with the HiFlow® sampler used for measurements of emissions from sources such as leaks and pneumatic controllers. Briefly, the HiFlow® sampler has two measurement modes: a low hydrocarbon concentration mode that uses catalytic oxidation and a higher hydrocarbon concentration mode that uses a thermal conductivity measurement. The transition between these modes occurs at when the hydrocarbon percentage in the leak exceeds approximately 5% of the total sample volume. Given the approximate overall sample intake rate of the HiFlow® sampler used in some measurements in Allen et al. (2013) and Allen et al. (2014) of 8 scf/min, the approximate size of the leak would be 24 scf/h for the cross-over between measurement modes to occur. The potential cross-over malfunction would occur if the instrument fails to transition between the two measurement modes, displaying an erroneous low value for the leak rate. This commentary outlines the steps that were taken by the Allen et al. (2013, 2014) study team to investigate the potential for the cross-over malfunction with the HiFlow® sampler used in Allen et al. (2013, 2014). While this evidence cannot resolve the existence of the cross-over malfunction for the entire population of HiFlow® samplers, the evidence does indicates that the cross-over malfunction was not a major cause of measurement error in Allen et al. (2013).

### Laboratory Testing of the HiFlow® sampler

After being used for field work in Allen et al. (2013) and before field work in Allen et al. (2014), the HiFlow® sampler and UT-Austin was modified by the manufacturer to report data at 2-3 second time resolution. In order to test the HiFlow® sampler after these modifications, laboratory testing was undertaken using pure methane and a wet gas surrogate (70.5% methane by volume) to compare the performance of the HiFlow® sampler to two other measurement devices (a mass flow controller and a supply gas meter with readings based on gas cooling of a heated flow sensing element). The performance of the HiFlow® sampler is documented extensively in the Supporting Information for Allen et al. (2014). Figure 1 shows sample data from one of the laboratory tests and demonstrates three instances of the HiFlow® sampler measurement exceeding 24 scf/h, indicating that the HiFlow® sampler was able to transition between the two measurement modes.

<sup>&</sup>lt;sup>1</sup> Center for Energy and Environmental Resources, The University of Texas at Austin, 10100 Burnet Road, Building 133, M.S. R7100, Austin, Texas, 78758

<sup>&</sup>lt;sup>2</sup>URS Corporation, 9400 Amberglen Boulevard, Austin, Texas, 78729

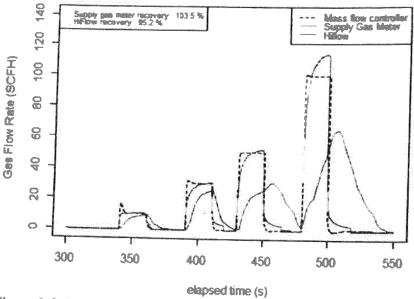


Figure 1. Laboratory test comparing the gas flow rate measurements of a mass flow controller, a Fox Thermal Instruments FT2A meter, and the UT-Austin HiFlow® sampler. The test consisted of four actuations of 20 seconds duration with maximum flows of 10, 30, 50, and 100 scl/h with an interval of 30 seconds between actuations (Allen, et al., 2014).

### Field Testing of the UT-Austin HiFlow R sampler

The Allen et al. (2014) study team participated in field testing of the UT-Austin HiFlow® sampler, with tests designed by investigators who have proposed the cross-over malfunction, at actual natural gas production sites with methane concentrations ranging from 77.0% to 90.8%. As shown in Figure 2, the UT-Austin HiFlow® sampler was able to cross-over between measurement modes during simulated pneumatic controller actuations (Figure 2A and 2C) and while in use on an actual pneumatic controller (Figure 2D). During this field work, the UT-Austin HiFlow® sampler only failed to cross-over between measurement modes on a single test (out of XX tests). This single cross-over failure occurred at the driest (90.8% methane composition) site. The Allen et al. (2014) does not believe that the single failed test was representative of typical use of the HiFlow® sampler for two reasons. First, the UT-Austin HiFlow sampler was powered down prior to sampling when the protocol for Allen et al. (2014) indicated that the calibration needed to be checked for the HiFlow® sampler each time it was turned on due to the potential for drift in the upper end calibration. Second, the test was conducted by the investigators, who have proposed the cross-over malfunction, outside typical operation conditions for the HiFlow® sampler by minimizing the intake air for sample dilution and by choosing a methane emission flow rate (~60 scf/h) that was above the average flow rate for 98% of the pneumatic controllers in Allen et al. (2014). After calibration, the UT-Austin HiFlow® sampler (Figure 2A) successfully crossed-over between measurement modes at a

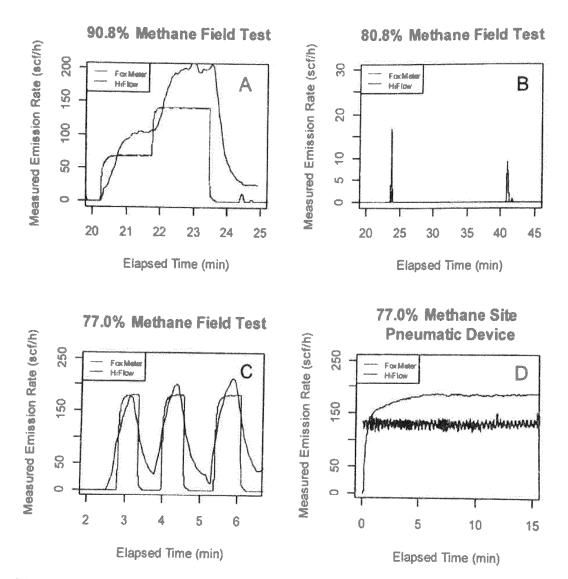


Figure 2. Results from field testing of the UT-Austin HiFlow® sampler. Plots A,B, and C were simulated actuation patterns using a rotameter and field gas. Plot D is a dual measurement on an in-service pneumatic controller with the measurement procedure described in Allen et al. (2014).

Analysis of Infrared Camera Scans from Allen et al. (2013)

Infrared (IR) video camera scans were taken and archived during field work for Allen et al. (2013) for some sites. If the cross-over problem were to have been prevalent, then the expectation would have been to find scans for which a large leak was detected by IR but that was not measured by the HiFlow® sampler. For pneumatic controllers, IR scans were available for 118 of the 305 (39%) devices in Allen et al. (2013). From this subset of data, 5 devices were found to have detectable emissions in the IR scan that were not measured in the subsequent HiFlow® measurement (it was not possible to simultaneously image the emissions using the IR camera and capture all of the emissions in a HiFlow® enclosure). None of these IR images appeared to be of large emissions, in the judgment of the Allen et al. (2014) study team. In

addition, 7 devices without emissions in the IR camera scan were found to have emissions between 0.2 and 5.0 scf/h, indicating that the intermittent venting of some pneumatic controllers was likely responsible for the difference in emissions detection between the two methods.

Comparison to Pneumatic Controller Measurements in Allen et al. (2014)

Based on the result from Allen et al. (2013) that emissions from pneumatic controllers, which were a subset of the devices that had been measured with the HiFlow® sampler, were higher than predicted based on existing inventories of natural gas production emissions, Allen et al. (2014) was undertaken as a follow-up study to investigate this source category. Allen et al. (2014) changed the primary measurement technique to focus on the measurement of supply gas to the controller using a Fox Thermal Instruments FT2A device rather than the exhaust gas measurement technique of Allen et al. (2013) using the HiFlow® sampler. This change in instrumentation was prompted by the desire to obtain higher time resolution data (0.1 second) than the HiFlow® sampler could provide (2-3 second) in order to better characterize the operation of the sampled pneumatic controllers. A comparison of pneumatic controller emission measurements at different natural gas methane compositions from Allen et al. (2013) to supply gas meter measurements in Allen et al. (2014) is available in Figure 3. It is important to note the difference in sampling strategy in Allen et al. (2014), which measured emissions from controllers on all types of natural gas and oil wells, compared to Allen et al. (2103), which focused on pneumatic controllers on recently-completed, hydraulically-fractured wells.

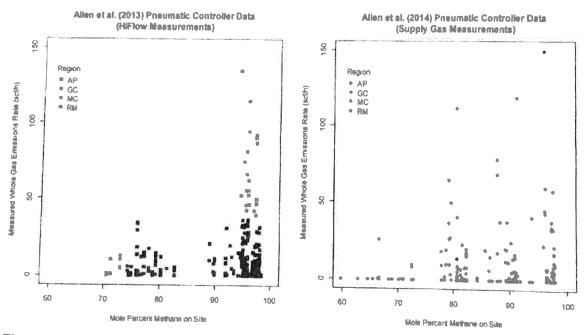


Figure 3. Comparison of the whole gas emission rate per pneumatic controller versus the mole percent methane in the site sales gas concentration for Allen et al. (2013), which was measured using the UT-Austin HiFlow® sampler, and the subset of data from Allen et al. (2014) that was collected using the Fox Thermal Instruments FT2A supply gas meter. Note that the dotted gray line represents the approximate cross-over hydrocarbon leak rate (24 scf/h) for the UT-Austin HiFlow® sampler at a total gas draw-in rate (including air) of 8 scf/min.

If the cross-over malfunction were to have been a major source of instrument error in Allen et al. (2013), the expectation would be that the results would be biased low compared to measurements in Allen et al. (2014); however, the average whole gas emission rate per controller of 5.5 scf/h was lower in Allen et al. (2014) than the average reported in Allen et al. (2013) of 11.2 scf/h. For wet gas sites (<85% methane composition) where investigators citing the crossover malfunction have posited a higher rate of cross-over failure, the average whole gas emission rate per controller was 6.3 scf/h and 5.3 scf/h for Allen et al. (2013) and Allen et al. (2014), respectively. In addition, the claim that the lower frequency of high emission rates for controllers at wet gas sites does not account for regional differences in pneumatic controller emissions that were documented in both Allen et al. (2013) and Allen et al. (2014). In both these studies, the emission rate from pneumatic controllers in the Rocky Mountain region was substantially lower than other regions such as the Gulf Coast, which Allen et al. (2014) attributes to lower rates of continuous bleed controllers in the sampled population. In Allen et al. (2013), 25% of the measured pneumatic devices on wet gas sites were located in the Rocky Mountain region. Excluding devices in the Rocky Mountain region, the average whole gas emissions rate per device on wet gas sites was 8.0 scf/h in Allen et al. (2013) and 7.7 scf/h in Allen et al. (2014). For the Gulf Coast region, which had the largest number of wet gas measurements in both studies, 13% and 14% of pneumatic controllers on wet gas sites had an average emissions rate that exceeded 24 scf/h in Allen et al. (2013) and Allen et al. (2014), respectively.

### Summary

While a cross-over malfunction issue may exist with some population of HiFlow® samplers, the evidence does indicates that the malfunction was not a major source of instrument error for the UT-Austin HiFlow® sampler used in Allen et al. (2013). The UT-Austin HiFlow® sampler was able to cross-over between measurement modes in controlled laboratory and field work settings. In addition, many of the findings for pneumatic controllers in Allen et al. (2013), such as the regional difference in controller emissions, were confirmed with a different measurement tool in Allen et al. (2014).

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Howard et al. citation

### APPENDIX C. Unpublished Allen Comments and Howard Response on Howard (2015b)

# Energy Science & Engineering

# Comment on "University of Texas study underestimates national methane emissions inventory at natural gas production sites due to instrument sensor failure"

Journal:	Eneray Science & Engineering
Manuscript ID:	ESE-2015-08-0064
Wiley - Manuscript type:	Response
Search Terms:	Natural gas, Environment
Abstract:	Howard (2015) claims an underestimation of emissions due to sensor failure in our report of methane emissions from natural gas production sites (Allen, et al., 2013). We disagree with these assertions.

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Manuscripts

### **Energy Science & Engineering**

Howard (2015) claims an underestimation of emissions due to sensor failure in our report of methane emissions from natural gas production sites (Allen, et al., 2013). We disagree with these assertions.

Howard (2015) asserts that the HiFlow® sampler, which has been used extensively in measuring natural gas emissions since the 1990s, has a design flaw that causes the instrument to fail to detect emissions that have high concentrations of heavier hydrocarbons, and that this sensor failure caused underestimated emissions in Allen et al. (2013). The primary evidence presented in support of this hypothesis is data from our previous work (Allen, et al., 2013), in which the fraction of devices with high emission rates was greater for sites with low heavy hydrocarbon concentrations in the produced gas (high methane concentrations) than for sites with lower methane concentration. Howard (2015) is correct in noting that we observed significant variations in methane emission rates in different natural gas production regions in the United States, however, he assumes that all regions should have similar emission rates and that therefore the differences are due to a failure of the HiFlow® sampler; this assumption is flawed. Different regions have great variations in operating practices, equipment on site, and local regulations. For example, parts of the Rocky Mountain region where Allen, et al. (2013) made measurements (which has high concentrations of heavier hydrocarbons in produced gas, low concentrations of methane), require leak detection and repair, control devices on tank venting and the installation of low bleed controllers. These controls are not currently required in many other regions, causing regional differences in emission rates. Other studies, in addition to Allen, et al. (2013), have observed regional differences in emission rates. For example, Peischl, et al. (2015) have reported very different emission rates in different natural gas production regions with high methane concentrations (dry gas), ranging from a low of 0.1830.41% of gas production in the northeast Marcellus, to rates of 1.0 to 2.1% in the Haynesville (a factor of 5 difference between two regions, both with dry gas (high methane fractions)). These are both regions sampled by Allen, et al (2013) and these differences (a factor of 5) point out the importance of local regulations, age of equipment, type of equipment and multiple other factors that influence emission differences between regions, in regions with similar methane content of produced gas.

As additional evidence of a problems with the of the HiFlow® sampler, Howard (2015) describes field testing of the HiFlow® sampler at a single field site. As described in a recent rebuttal to a comment that made a similar claim (Allen, et al., 2015a):

"The study team [of Allen, et al., 2013] participat ed in a two3day field test of several HiFlow® samplers. Participants in the field testing inclu ded our team, the commenter, a consulting firm, an instrument provider and consult ing firm, and a natural gas producer. During this field test, the UT HiFlow ® sampler [the sampler used in Allen, et al. (2013, 2015b)] successfully crossed3over on sites with met hane concentrations in the produced gas ranging from 77%–91%. Over two days of testing, the UT HiFlow® sampler crossed3 over successfully in all but one test; that test oc curred at a site with produced gas containing 91% methane. Subsequent examination of the instrument indicated that it had lost calibration after losing power, then being restarted by personnel not on our study team. The sampling protocol in Allen et al. required a calibration check each time the HiFlow® sampler was turned on. Once the calibration protocol was followed, the HiFlow® sampler resumed proper operation."

Howard (2015) notes the successful operation of our HiFlow® sampler at test sites with methane concentrations as low as 77%, but does not explain how this is consistent with his assertion that the HiFlow® instrument consistently fails at low methane concentrations. In the same rebuttal (Allen, et al., 2015a) we noted that we had also done laboratory testing of the HiFlow® sampler used by Allen, et al. (2013), and additional data analyses of infrared camera data also collected by Allen, et al. (2013). That information will not be repeated here, but the data and analyses indicate that sensor failure did not significantly impact the measurements made with the HiFlow® sampler, in either Allen et al. (2013) or subsequent work using the sampler (Allen, et al., 2015b).

The previously published rebuttal (Allen, et al., 2015a) also compares results among multiple studies of emissions from pneumatic controllers, using the HiFlow® sampler and other types of sampling devices. Howard (2015) argues that these comparisons should not be considered. However, these two studies, using two different measurement methods, showed the same type of regional distributions of emissions for pneumatic controllers (high emissions per controller in the Gulf Coast, low emissions per controller in the Rocky Mountains). The average emissions measured using a supply gas meter (Allen, et al., 2015b) were in fact lower, by about a factor of 2, than the emissions reported in Allen, et al. (2013) made using the HiFlow® sampler. This is just the opposite of the effect that would be expected if the HiFlow® sampler were missing high emitting devices.

Finally, in Allen et al. (2013), measurements were made downwind of about 13320% of the sampled sites (the percentage depended on the type of site), to independently assess whether the on3site measurements, including the emissions measured using the HiFlow® sampler, were accurately quantifying emissions. Howard (2015) uses these data to perform a number of complex comparisons, which focus on percentage differences between the on3site and downwind measurements, particularly at sites with low methane concentrations in produced gas. These analyses obscure 2 simple facts.

- 1. The independent downwind measurements in the Rocky Mountain region (10 sites with 40 wells), the region with the lowest average methane concentration in produced gas, reported by Allen, et al. (2013), are lower (0.66 standard cubic feet per minute (scf/m) per site, or 0.17 scf/m per well) than in other regions with higher methane concentrations in the gas. For example, in the Mid3Continent region, emissions at 5 sites with 10 wells averaged 3.0 scf/min per site or 1.5 scf/min per well. Thus, the independent downwind concentrations also found regional differences in emission rates; regions with low methane fractions in produced gas were observed in the downwind sampling to have lower emissions than regions with higher methane fractions.
- 2. The average per well emissions in the Rocky Mountains, made using independent downwind sampling at sites with 40 wells, were low. The average emission rates from these wells were less than half of the emissions that would be expected from just one high emission rate source per well that Howard (2015) argues should be prevalent at sites with high methane concentrations. Simply stated, if there were missing emissions of the magnitude asserted by Howard (2015), they would have significantly increased measured downwind concentrations. The downwind data, made completely independently of the

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HiFlow® measurements, indicate a lower frequency of high emitting sources at sites with low methane concentrations in produced gas in the Allen, et al. (2013) data set.

Overall, based on multiple independent measurements (IR camera scans, downwind sampling, and parallel direct flow and HiFlow® measurements) we conclude that sensor failure did not significantly impact the measurements made with the UT HiFlow® sampler in either Allen et al. (2013) or Allen, et al. (2015b).

### Acknowledgments

The authors thank other authors of Allen, et al. (2013, 2015b) and technical experts from the study sponsors for their input.

### **Disclosures**

The authors declare the following competing financial interest(s): Lead author David Allen has served as chair of the Environmental Protection Agency's Science Advisory Board (201232015), and in this role was a paid Special Governmental Employee. He is also a journal editor for the American Chemical Society and has served as a consultant for multiple companies, including Eastern Research Group, ExxonMobil, and Research Triangle Institute. He has worked on other research projects funded by a variety of governmental, nonprofit and private sector sources including the National Science Foundation, the Environmental Protection Agency, the Texas Commission on Environmental Quality (TCEQ), the American Petroleum Institute and an air monitoring and surveillance project that was ordered by the U.S. District Court for the Southern District of Texas. David Sullivan has worked on other research projects funded by the TCEQ, the California Air Resource Board, the Texas Air Research Center, and the U.S. District Court for the Southern District of Texas. Matt Harrison, who worked for URS at the time of the publication of the original papers (Allen, et al., 2013; Allen, et al., 2015b), is now an employee of AECOM, a company that purchased URS. Financial support for the original reports (Allen, et al., 2013; Allen, et al., 2015b) was provided by were Environmental Defense Fund (EDF), Anadarko Petroleum Corporation, BG Group plc, Chevron, ConocoPhillips, Encana Oil & Gas (USA) Inc., Pioneer Natural Resources Company, SWEPI LP (Shell), Southwestern Energy, Statoil, Talisman Energy USA and XTO Energy, a subsidiary of ExxonMobil. Funding for EDF's methane research series, including the University of Texas study, is provided for by Fiona and Stan Druckenmiller, Heising3Simons Foundation, Bill and Susan Oberndorf, Betsy and Sam Reeves, Robertson Foundation, Alfred P. Sloan Foundation, TomKat Charitable Trust, and the Walton Family Foundation.

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Dr. Allen and colleagues from the University of Texas (UT) (1) argue that sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS) did not affect their 2013 UT study (2) as I presented in (3). This is a welcome and critically important discussion because sensor failure in the BHFS may cause both underreporting of methane ( $CH_4$ ) emissions and underestimation of the health effects from air emissions at oil and natural gas (NG) facilities. Most importantly, however, the BHFS is also used to prioritize the repair of NG leaks, and if a large leak were not repaired because the BHFS underestimated it, this could lead to catastrophic component failure and/or explosion.

Although the rebuttal by (1) contends that the BHFS has been used since the 1990's, the BHFS has actually only been commercially available since 2003. High flow sampling measurements of NG leaks made prior to this were done with custom built instruments based on my design, which Bacharach, Inc. then developed into the BHFS. However, I am not affiliated with Bacharach, Inc. and I was not associated with the development of the BHFS.

The primary evidence of sensor failure is not the lack of high emitters in the UT BHFS data set (2) as stated by (1) but rather the direct experimental observance of this failure, which has been reported in (4) and (5), and, as summarized in (3), has been observed in four out of six samplers that were tested using NG with CH<sub>4</sub> content of < 91%. However, because the UT BHFS data set (2) contains measurements of several different types of sources with wide ranges of natural gas compositions, it provides a unique opportunity to evaluate the possibility that the occurrence of sensor failure might be widespread. It is certainly important to recognize that the BHFS measurements in (2) were biased low by sensor failure so that this data set is not relied upon to inform public policy. However, the much more important result of my analysis (3) of the UT BHFS data set is that sensor failure could indeed be widespread, since it appears to have occurred when measuring NG streams with CH<sub>4</sub> concentrations as high as 97%. This means that BHFS measurements throughout all sectors of the NG industry could be affected.

A third point of confusion is the contention by (1) that air pollution regulations in the Rocky Mountain region resulted in lower emission rates in that region, and that this explains the lack of high emitters at sites with lower  $CH_4$  content observed in their study because that region also had a lower  $CH_4$  content in the wellhead gas. Air pollution regulations might indeed result in lower emission rates in the Rocky Mountain region, but my analysis in (3) explains in detail that this is clearly not the cause of the scarcity of high emitters at sites with wellhead gas of lower  $CH_4$  content. To summarize, my analysis explains that:

- 1) Even when the Rocky Mountain region is excluded, there are still almost four times fewer high emitters at sites with wellhead NG compositions < 91% CH<sub>4</sub> than sites with > 91% CH<sub>4</sub>;
- 2) Pneumatic device emissions measured using flowmeters in a UT follow-up study (6) show a complete reversal of the pattern of pneumatic device emissions measured by BHFS in the UT study (2), i.e., when measured by flow meters, there was a larger occurrence of high emitters at sites with low well head gas CH<sub>4</sub> content;
- 3) Emission rates measured by BHFS reported by (2) within a single region Appalachia show a dramatic pattern of decreasing occurrence of high emitters as wellhead  $CH_4$  concentration decreases over a narrow range from 98 to 95%  $CH_4$ ; and

4) Although the downwind tracer measurements (discussed in further detail below) made by (2) confirm that emission rates in the Rocky Mountain region were lower than other regions, these measurements also confirm that the BHFS measurements are too low at sites with low wellhead gas CH<sub>4</sub> content, even in the Rocky Mountain region.

It was also asserted by (1) that both field and laboratory testing showed little evidence of the sensor failure. As described in (3), I tested the sampler used in the UT study after the publication of their initial results in (2) in the presence of members of the UT field team and observed the sensor failure during this testing (4). This failure occurred even though the sampler had been upgraded to a new generation of firmware after it was used to conduct the measurements made during the initial UT study (2). After I conducted this field testing, I immediately interviewed two experienced BHFS technicians not associated with the UT team who reported that the new generation of firmware had eliminated problems in their samplers that caused leaks too be reported too low. Given the dramatic improvement in performance of samplers reported by these technicians using the updated generation of firmware, it is not surprising that the sensor failure only occurred sporadically in the UT sampler during the field tests and was not observed in their laboratory tests. Indeed, it is rather surprising that sensor failure occurred at all in a unit with updated firmware, although this highlights that the factors affecting sensor failure are still not well understood. I immediately relayed these reports of improved performance of samplers with updated software to the UT team in March of 2013, so the authors of (1) and (2) are well aware that the performance of the UT sampler could have been much worse when it was used for the original UT study (2), during which time it had older firmware. It is also interesting to note that during the March 2013 field testing, the UT team had a second BHFS that they did not allow me to test, stating that it had too many problems to make testing it worthwhile, although the nature of those problems was not specified.

The rebuttal (1) further asserts that the reason sensor transition failure occurred in the UT sampler during the field testing I conducted was that the proper UT calibration protocol was not followed. As I explained in (3), the UT team made no effort to conduct calibrations after the instrument was turned off and on but only did so after sensor failure was noted. Consequently, in contrast to what they have stated in (1), it does not appear that the UT protocol was to calibrate any time the instrument was turned on.

Allen and his colleagues (1) also state that because the average emission rates of pneumatic devices measured by flow meters in their follow-up study (6) are lower than those measured by their BHFS in (2), this disproves the possibility of sensor failure since sensor failure should cause the BHFS measurements to be lower. However, as I explained in (3), the pneumatic device data collected by BHFS (2) were clearly not a random sample but instead focused only on emitting devices and inadvertently excluded zero emission sources. This is one reason why average pneumatic device emission rates calculated from the BHFS data (2) are higher than those calculated from the flow meter data (6). Additionally, much of the pneumatic device data collected by flow meters (6) was likely biased low due to calibration problems. The authors of (6) only calibrated their meters before and after their field work, and claim in their supplemental information that they only became aware of a calibration problem with one meter during their post project calibration. However, as I reported in (7), I also tested the UT flow meters in March of 2013 while the measurements for the follow-up study (6) were ongoing, again in the presence of the UT field team. During these tests, one of their two primary meters indicated flow rates that were a factor of three lower than the actual flow rates released through the meters. Even

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after applying their post project calibration correction (6), the flow rates measured by this faulty meter during these tests would still be a factor of two lower than the actual flow rates. These two additional failures of quality assurance – the inadvertent exclusion of zero emitters from a supposedly random sample of devices in (2) and the inadequate calibration of flow meters in (6) – further highlight the need for dramatic improvements in greenhouse gas measurements programs.

Allen and colleagues (1) also maintain that infrared camera data showed no evidence that the BHFS did not accurately measure high emitters; however, there is ample evidence that infrared camera visualization cannot be currently used to quantify leaks. For instance, during the Ft. Worth Air Quality study (8), daily QA checks on the IR camera indicated variations in factors of up to 15 in the distance at which a known leak could be identified, much less quantified, under calm conditions. This large variability, even under calm conditions, demonstrates the huge uncertainty in trying to quantify emission rates with an IR camera, since any air movement near the leak would dramatically increase this variability.

Finally, their rebuttal (1) also states that my comparison (3) of the downwind tracer measurements to the on-site emissions measurements in the UT study (2) is "complex" and obscures the fact that the average emission rates from wells in the Rocky Mountain region were too small for the sensor failure to have occurred. In particular, they state: "The average per well emissions in the Rocky Mountains, made using independent downwind sampling at sites with 40 wells, were low. The average emission rates from these wells were less than half of the emissions that would be expected from just one high emission rate source per well that Howard (2015) argues should be prevalent at sites with high methane concentrations. Simply stated, if there were missing emissions of the magnitude asserted by Howard (2015), they would have significantly increased measured downwind concentrations."

However, this claim by (1) ignores the fact that the downwind tracer technique was used to measure  $CH_4$  emissions not from individual wells but from sites with an average of almost five wells per site, so the emission rates per site are much higher than the emission rates per well. In fact, the average emission rate per site measured by downwind tracer in the Rocky Mountain region was 0.66 scfm, over 50% greater than the expected BHFS sensor transition threshold of 0.4 scfm at a sample flow of 8 scfm. If the BHFS sample flow were reduced to 4 scfm due to low battery power or a tightly wrapped enclosure, then sensor transition failure could occur when measuring a source as small as 0.2 scfm. Consequently, a single measurement of a high emitter at these sites that was biased low by sensor failure could cause the observed underreporting of BHFS measurements compared to the tracer data.

To illustrate this, and because Dr. Allen and colleagues (1) found my comparison in (3) of their downwind tracer and on-site data (2) to be complex, I have tried to simplify that analysis here. Figure 1 presents the downwind tracer and on-site data from the UT study (2). For this analysis, I have removed only the two sites at which 98% or more of the reported on-site totals were comprised of estimated emissions, as opposed to actual BHFS measurements, since such a large fraction of estimated emissions would prevent a reasonable evaluation of the BHFS performance.

As seen in Figure 1, the downwind tracer data do in fact indicate that there are real regional differences in  $CH_4$  emissions from natural gas production, as (1) have asserted and as I have acknowledged in (3).

However, Figure 1 also shows clearly that the lower emissions in the Rocky Mountain region do not preclude the occurrence of BHFS sensor failure. When comparing the results on a site by site basis, the on-site totals (which as noted previously were a combination of BHFS measurements added to estimates of sources not measured) are substantially lower than the downwind tracer results for the Rocky Mountain and Mid-Continent sites where  $CH_4$  content was less than 82%, and substantially higher for sites in Appalachia where  $CH_4$  content was greater than 97% (sensor transition failure is much more likely at  $CH_4$  concentrations less than 97% (3)). Only one out of 13 sites with  $CH_4$  content < 82% (RM-5) had reported on-site emissions greater than the emissions measured by tracer, while all four sites with  $CH_4$  content > 97% had on-site emissions greater than those measured by tracer. The ratio of total on-site emissions to downwind tracer emissions for each region was as follows: Mid-Continent: 0.586; Rocky Mountain: 0.461; and Appalachia: 1.44.

Since the reported on-site emissions were greater than those measured by downwind tracer at all sites with well gas content of  $CH_4 > 97\%$  (the Appalachia region) where the BHFS likely functioned properly, I conclude that the estimation methods used by the UT study (2) actually overestimate emission rates as compared to actual whole-site emissions measured by downwind tracer analysis. Consequently, although this simplified comparison indicates that the on-site data are a factor of two too low at the Mid-Continent and Rocky Mountain sites, the actual effect of BHFS sensor failure is probably larger because the overestimates of emissions from the sources that were not measured somewhat obscures the underreporting by the BHFS, and I've discussed this in detail in (3). Therefore, although this direct comparison of the downwind tracer measurements to the on-site data for each site independently verifies the BHFS sensor failure, it does not reflect the full magnitude of the problem.

Given that the BHFS sensor failure can cause underreporting of natural gas emission rates which could create critical safety, health, and environmental problems, it is disappointing that (1) are willing to ignore the clear evidence – provided by their own downwind tracer measurements – of the effects of sensor failure in the UT BHFS (2) data set. The lead author of (1) and (2) served as the chair of the EPA Science Advisory Board during the period of research conducted by (2), and as such has a special obligation to disclose this issue since the BHFS is an EPA approved instrument. The BHFS is currently the standard instrument in the natural gas industry worldwide for measuring leak rates, and although upgrading firmware may reduce sensor failure, it does not eliminate it, and it is likely that most BHFS's in use have older firmware more susceptible to sensor failure. The presence of such a problem that can result in large leaks being reported as an order of magnitude or more lower than they actually are presents a frightening safety issue. It may have also caused many CH<sub>4</sub> emission inventories to be biased low, including those compiled by the USEPA Subpart W Greenhouse Gas Reporting program (9), the American Carbon Registry (10), and the United Nations Clean Development Mechanism (11).

For the last 12 years I have served as a professional firefighter, and in that role I have seen the tragic consequences that can occur when safety issues are ignored. Unfortunately, the misguided defense by such prominent researchers (1) of the UT BHFS data set (2) creates a distraction from the critical safety, health, and environmental problems that the BHFS sensor failure presents to the oil and NG industry. I call upon the authors and sponsors of the UT study (2) to meet their obligations to the safety of industry personnel and to the health of communities near oil and NG facilities by retracting the UT BHFS data set (2) so that this critically important problem can be recognized and addressed immediately.

### **Energy Science & Engineering**

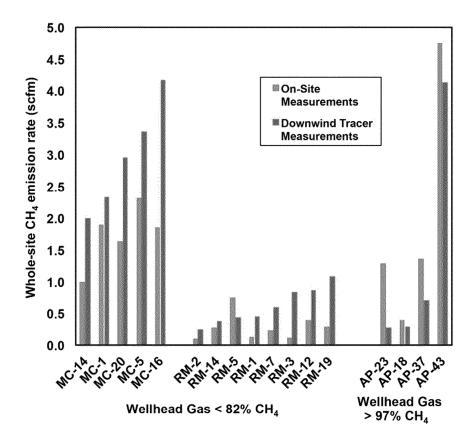
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### **Figure Captions**

Figure 1. Comparison of downwind tracer measurements to reported on-site emission rates (compiled from BHFS measurements and estimates of sources not measured) in the UT study (2). Sites with lower CH4 wellhead gas content, where the BHFS is likely to experience sensor failure, have dramatically lower on-site emission rates compared to emission rates at the same sites measured by downwind tracer techniques. This comparison provides independent corroboration of the BHFS sensor failure, even in the Rocky Mountain region where tracer measurements indicate lower regional emission rates. BHFS = Bacharach Hi-Flow Sampler; MC = Mid-continent; RM = Rocky Mountain; AP = Appalachia.



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# Appendix D. Problems with the Fox Meter

# Analysis by Touché Howard of Fox Meter Calibration Problems in the Allen et al. (2014) EDF Phase II Study of Pneumatic Devices

In December of 2014, Allen et al. (2014) published a study of emission rates from pneumatic devices conducted by the University of Texas (UT) and sponsored by EDF and corporate partners. This study, also known as the UT Phase II pneumatic study, was a follow-up to Allen et al. (2013) (known as UT Phase I). There may be almost 1,000,000 pneumatic devices in the production segment of the oil and gas industry and they may contribute over 25% of methane emissions from this segment. Additionally, at sites with higher compositions of heavier hydrocarbons, pneumatic devices may contribute substantially to the release of air toxics that could affect the health of surrounding communities. Consequently, accurate measurements of pneumatic emission rates are crucial for understanding the true contribution of these devices to both methane and air toxics emissions throughout this segment of the industry and to provide good guidance to policy makers and community representatives.

A total of approximately 360 devices were measured in the Phase II Allen et al. (2014) study. There were two major differences between the Phase I and Phase II studies, however. First, the Phase I study inadvertently focused on devices that were emitting, as opposed to the random sample that was intended (Allen et al. 2014, Howard 2015b), while the goal of the Phase II study was to measure every pneumatic that it was possible to survey at each site visited, providing a more representative sample. Second, the primary measurement method for Phase II was to install a Fox FT-2 flow meter in the supply gas line with some measurements made using the Bacharach Hi-Flow Sampler (BHFS); during Phase I all measurements were made using the BHFS.

The Phase II field program ran from approximately December of 2013 through at least March of 2014. The final end date is not known. On March 18, 2014, while conducting an independent test of the UT BHFS that had been used during the Phase I program, I also tested the two Fox meters that the UT team was using for Phase II. (I was not associated with the UT team but these tests were set up by Carrie Reese of Pioneer Natural Resources because I had expressed concern that the UT BHFS had experienced sensor failure during Phase I (Howard 2015b).)

While testing the two UT Fox flow meters against my rotameter, I found that one of their Fox flow meters (Fox Meter A) was reporting emission rates too low by almost a factor of three (e.g., if the actual emission rate was 60 scfh, the Fox meter would report the rate as 21 scfh, and a correction factor of 2.86 would be required). The other meter compared well with my rotameter, indicating my test method was accurate, and these tests were made in the presence of the UT team including Matt Harrison and Adam Pacsi, as well as Carrie Reese of Pioneer Natural Resources and Tom Ferrara of Conestoga Rovers and Associates (now GHD).

Upon seeing the problem with Fox Meter A during my test on March 18, 2014, Matt Harrison of URS (now AECOM), the lead consultant for the UT team, stated: "Yeah, everyone knows that meter is flaky. You can hook it up to a pneumatic, hear the pneumatic fire, and not see anything on the meter."

The UT team took Fox Meter A out of service that day and the data sheets from the test were provided to them. Additionally, Carrie Reese confirmed to me that she reported the meter problem to Dr. Ramon Alvarez at EDF when she returned from the field.

Surprisingly, the UT team was doing no calibration checks in the field to prevent problems like this. My test was the first check of the meters that had been done since the meters had been calibrated at the start of the project. Because many of the sites the UT team surveyed had higher concentrations of heavier hydrocarbons, there was a high possibility that one or both meters could become fouled, given that the heavier hydrocarbons are often seen to accumulate on the pneumatic devices. Additionally, the Fox flow meter manual specifically states that the meter will read too low if it becomes dirty.

However, when the Phase II Allen et al. (2014) study was published in December of 2014, I was surprised to see that no mention was made of the March 18, 2014 Fox flow meter test. Instead, in a footnote in their supplementary information, the authors indicate that during their post calibration check they found that one meter was reporting too low by 34%, requiring a correction factor of 1.52. (Consequently, if the UT correction factor were applied to correct the results of the faulty meter on the day that I tested it, the corrected results would still be about half the actual flow rate, since I found it to be measuring low by a factor of almost 3.) Additionally, in order to determine at what point the meter calibration problem started, they reviewed the quality assurance checks that had been made by doing a subset of simultaneous measurements comparing the Fox flow meters to the BHFS.

Unfortunately, the failure of the authors to disclose the test I conducted invalidates the Allen et al. (2014) data set, because they specifically suppressed that independent testing showed the performance of their faulty meter was much worse than they reported in their supplementary information. Moreover, beyond this failure to report the March 18, 2014, flow meter test, there are additional troubling questions.

First, it seems inconceivable that any researcher, once shown by independent tests that an instrument was giving incorrect results, would not immediately test that instrument themselves and immediately institute more rigorous calibration checks of the instruments. However, this is what is implied by Allen et al.'s (2014) supplemental information and by Allen et al.'s (2015) response to my letter to ES&T (Howard 2015a), where they state that they found the problem during their post project calibration check. Consequently, this indicates that they took no action when I demonstrated that one Fox flow meter was reading far too low.

If this is the case, then the failure to immediately investigate this problem and to implement improved calibration checks indicates a complete disregard for quality assurance, and provides further evidence that the data set should not be relied upon.

However, it seems more likely that the authors did in fact investigate the problem and conducted their own tests of the Fox flow meter immediately after the March 18, 2014, tests, but did not disclose that they had done this. If so, this raises the troubling possibility that the authors may have then tried to correct the problem by cleaning the meter, but did not disclose that they had done that. This would explain why the meter performance improved between the March 18, 2014, test and the UT post project calibration test. (It is also possible that the meter performance simply varied greatly over time, but this would be another indication of poor data quality.) If the authors cleaned Fox flow meter A but did disclose this fact, and then went on to claim that the post project calibration was representative of the meter performance from the point they supposedly identified where the problem occurred, then this would be an additional fraud.

So the key questions for the EPA OIG and the editor of ES&T to ask regarding this issue are:

- 1) Did the authors of Allen et al. (2014) really not do any further investigation of the Fox flow meter problem after it was identified on March 18, 2014, but actually waited until the end of the project to do any other calibration checks?
- 2) If this is not the case, and the UT team actually did test their Fox flow meters immediately after the March 18, 2014 test, did the UT team also clean or adjust Fox flow meter A in any way to try to correct the problem, so that in fact the post project calibration check is not representative of the meter performance?

There are also serious questions about how the authors identified when they thought the meter calibration problem started during their field program. Because they did not conduct any routine calibration checks, there was no way to identify when this problem occurred in real time. Their solution was to compare the subset of 29 BHFS measurements that were made simultaneously with the 333 Fox flow meter measurements.

In Allen et al. (2014) the authors state, "Because we were making measurements using both the UT HiFlow sampler and the flow meters for a subset of controllers in the field, we were able to identify the site at which a step change occurred in the flow measurement performance of the Fox A meter, due to deposits on the thermal conductivity sensor. We applied a correction factor, based on pre- and post-study testing done in our laboratory, to the flow rate."

There are three critical problems with this approach. First, it assumes that the performance of the meter would remain constant once the problem occurred, and it's clear from the difference in response during the March 18, 2014, test and the post project calibration that this wasn't the case.

Second, the authors say they identified a step change in the meter response between meter measurements on subsequent days using the BHFS measurements. This would indicate that the change was equal to or greater than the decrease in response seen when they did the post project calibration, which was a decrease of 0.34, meaning that post project the meter read only 0.66 of the correct response. However, as seen in Figure 1, two thirds of the measurements made by Fox Meter A that the UT team flagged for correction read less than 0.66 of the BHFS measurements, and most were substantially worse than this. Consequently, it would not be possible based on these data for the authors to know at which of these times – if any – the meter became dirty. There is simply far too much uncertainty in these comparisons.

The third (and most troubling) issue with how the authors tried to identify where the meter problem occurred centers on how unlikely it is that the problem occurred where they say it did. Again, the key issue is that the authors state that the problem was identified by a step change in the meter performance that occurred in between two back-to-back meter tests that each had a BHFS measurement as well.

Because the authors pinpointed that the meter problem occurred specifically in between two measurements that each had BHFS measurements as well, they were able to implement their post project calibration correction without eliminating any data. In contrast, if the meter problem had occurred at a point in the data collection when a BHFS measurement hadn't been made simultaneously, then some amount of data would have had to be eliminated.

A thought experiment may make this clearer. If there were a corresponding BHFS measurement for every Fox flow meter measurement, then no matter when the Fox Meter A problem occurred, the BHFS measurement would be able to pinpoint it, assuming that the measurements made by the BHFS and Fox meters were accurate.

However, there were only 29 BHFS measurements that were made simultaneously with the 330 Fox flow meter measurements, and these BHFS measurements were not spaced evenly throughout the project. Instead, there were long periods where no BHFS measurements were made, and other periods where multiple BHFS measurements were made on a given site. For instance, no BHFS measurements were made in the Appalachia region, so if the problem had been discovered after that region had been done, all of the data collected by Fox Meter A in that region would have had to be discarded.

Since only 29 simultaneous BHFS measurements were made along with the 333 Fox flow meter measurements, this means that there was at best a 9% chance that the Fox meter problem would occur between two subsequent Fox meter measurements that also had BHFS measurements. However, as seen in Figure 2, most of the BHFS and Fox flow meter measurements are either too small or don't agree well enough (within a factor of two, since their reported correction was only 1.52) to be able to identify where this meter problem occurred. In fact, only 5 of the 333 Fox meter measurements (1.5%) are large enough and also

have BHFS measurements that agree well enough that they could be considered candidates for identifying where the meter problem occurred.

But of those five, only four were measured using Fox Meter A, and of those four, only one measurement also had another measurement immediately before it with no other measurements taken in between.

Consequently, there is only one place in this data set of 333 measurements that had all the necessary information (large enough readings, adequate agreement between the BHFS and the Fox flow meter, and back-to-back measurements with no measurements in between) that could possibly be used to identify where this meter problem occurred without the need to discard any of the Fox flow meter data. This equates to a 0.3% chance of the meter problem actually occurring just at the right spot where all these variables aligned so that no data would have to be eliminated. But that, in fact, is exactly where the authors say the meter problem occurred.

The most charitable interpretation of this unlikely scenario is that the authors did not understand how terrible their quality assurance results were, and they picked the only spot that happened to meet the requirements that they needed, even though it is clear that the BHFS measurement comparisons were far too uncertain to make such a determination.

However, given that the authors hid the existence of the March 18, 2014, test from the ES&T journal editor, reviewers, and readers, it is possible that they also manipulated data points in order to create a place in the data set that would allow them to create this scenario. It may not be possible to determine if this occurred, but it is a clear possibility.

Although I originally thought that it might be possible for the UT team to use the data from the other meter, the failure to fully disclose the Fox Meter A problem and the poor quality assurance comparisons with the BHFS measurements have since made it clear that this data set cannot be salvaged.

Figure 1.

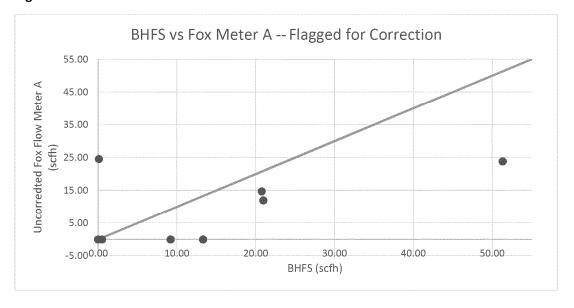
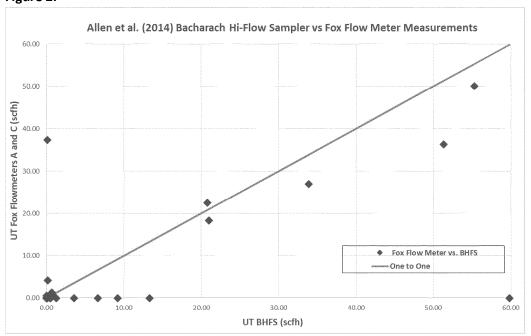


Figure 2.



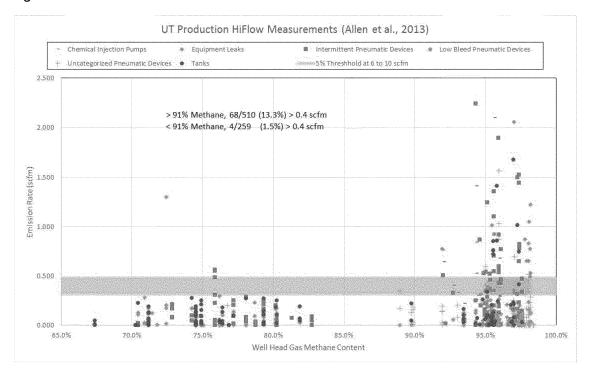
# Appendix E. Tank Emissions Data

# Analysis by Touché Howard

Allen et al. (2013) ("UT Phase I") collected methane emissions data using the Bacharach Hi-Flow Sampler (BHFS) for pneumatic devices, chemical injection pumps, equipment leaks, and tanks. Although they published all of these data, the only category they did not use to calculate their national emissions estimate were the tank data. This raises the possibility that the University of Texas (UT) team did not use the tank data because they were aware that the Bacharach Hi-Flow sampler was underreporting emission rates from tanks, but did not disclose that information.

We know from Howard (2015b) that all of the UT Phase I BHFS measurements were affected by sensor transition failure, which causes the BHFS to underreport emission rates when it does not transition from the low scale to the high scale. This problem appears more prevalent when the methane content of the site gas is lower (<95%). However, in the UT Phase I study, the BHFS was able to measure at least a few high emitters of pneumatic devices, chemical injection pumps, and equipment leaks at sites having gas with less than 95% methane. For tanks, however, the BHFS was not able to measure any high emitters until the site gas methane content was greater than 95.5% (Figure 1), so it appears the sensor failure was very prevalent when measuring tanks.

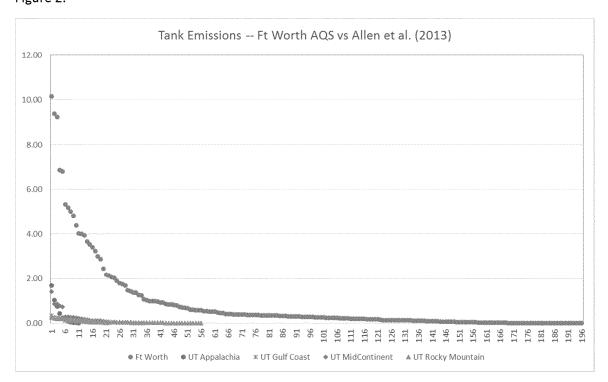
Figure 1.



This is consistent with Modrak et al. (2012), where those authors found that the BHFS consistently underreported emissions from tanks, although it was not until Howard et al. (2015) reanalyzed those data that it became apparent that this was due to sensor transition failure. (This paper was initially brought to my attention in late 2012 by Matt Harrison of URS Corporation, who was the lead consultant for the UT field team measurements.) It is also consistent with my own recent experience using a BHFS to measure emissions from tanks. Even though that sampler had new generation software and a current calibration, both of which should improve the sampler's performance (Howard et al. 2015), that BHFS repeatedly experienced sensor failure while measuring emissions from tanks, resulting in severe underreporting. Additionally, I was told by a representative of Heath Consultants (the US distributor for the Bacharach sampler) in June of 2015 that they did not recommend using the Bacharach sampler to measure tank emissions.

Finally, Figure 2 compares the UT Phase I (Allen et al. 2013) tank data to tank data gathered in the Fort Worth Air Quality study (ERG 2011), and indicates the tank emissions measured in the UT Phase I project appear to be unrealistically low, most likely due to BHFS sensor failure. Canister data collected from the outlet of the BHFS used during the Fort Worth study indicated the sampler used in that study was able to accurately measure emissions except in a few instances (Howard et al. 2015), probably because the natural gas in the Fort Worth area has a very high methane content.

Figure 2.



Because the Appalachia region measured by UT Phase I (Allen et al. 2013) also had a very high methane content in the natural gas (generally greater than 95% methane), it would be expected that the BHFS might still make accurate measurements of tank emissions in that region. This appears to have been the case, since 27% of the tank measurements that UT made in Appalachia exceed 0.4 scfm (standard cubic feet/minute), similar to the 31% of the tank measurements in the Fort Worth study that exceed 0.5 scfm. This threshold of 0.4 scfm is the emission rate above which the BHFS must transition from its low scale to its high scale to make accurate measurements, so it appears that a similar number of successful transitions occurred in both the UT Appalachia measurements and the Fort Worth measurements. However, only 14% of the UT measurements in the Midcontinent region and none of the measurements in the Gulf Coast or Rocky Mountain regions exceeded this threshold, indicating that the measurements in these regions (which had lower methane content in the site gas) were affected by sensor transition failure. (Note: if measurements were made in the Rocky Mountain region at the outlet of emission controls, then it would be expected that those measurements would be lower.)

This threshold of 0.4 scfm also represents an emission rate range for tank emissions where the emissions become noticeable due to smell and the shadows cast by the emission plume. Based on personal experience, tank emission rates greater than 1 scfm become very obvious, and both the Fort Worth data and the UT Appalachia data indicate that approximately 18% of tank emission rates would be greater than 1 scfm (again, this might be reduced somewhat by controls in the Rocky Mountain region).

Consequently, it seems odd that the UT team could make 124 measurements of tank emissions using the BHFS without noticing that it wasn't working well, and raises the possibility that the reason they didn't use those data was because they knew the sampler was underreporting emissions from tanks, even if they didn't know at the time that the problem was sensor transition failure.

The supplementary information from Allen et al. (2013) gives two reasons for not using the tank data. The first was:

"Emissions for tanks were not examined because access to the multiple potential leak sites on tanks would have required a lift at each site, severely limiting the number of sites that could have been visited." SI, page S-25.

Although that's true, the UT teams were still able to make 124 tank measurements, and 68 of those were outside of the Rocky Mountain region, where some tank vents may have gone to combustors to reduce emissions. It's not clear if they used the BHFS to measure emissions from combustors since that exhaust stream might be too hot, but if they did, those data could also be used.

They also state in Table S6-1:

Emissions from these tanks, while a potentially large source, are considered well defined and known, with working models and equations of state. Therefore these were not a primary study target, but were measured in some opportunistic cases.

Unfortunately, in contrast to their statement above, emissions from tanks are not well defined or easily modeled. Tank emissions are not caused solely by dissolved methane coming out of the liquids in the tanks, but are also due to leaking inlet valves and other episodic events, such as thief hatches (access ports for sampling) leaking or being left open, or leaking pressure relief valves.

The UT Phase I data themselves show that tank models are uncertain. They used tank models to estimate emissions for the 20 sites at which they also did downwind tracer emission measurements. There is only enough information to compare their modeled tank emissions to their actual measured tank emissions at 8 of those sites, but for those 8 sites, the measured emissions are more than a factor of ten larger than the modeled emissions, so clearly the models are not accurate.

Additionally, based on the tank modeling they did at the subset of 20 sites, tank emissions would comprise approximately 50% of the total site emissions, whereas the other categories they measured by BHFS (pneumatic devices, chemical injection pumps, and equipment leaks) would comprise the other 50% of emissions. This means that tanks could by far be the most dominant methane source at production sites in routine operation.

A recent study published by EDF (Lyon et al. 2016) in fact confirms this, where helicopter surveys found that 92% of the large emitters at production sites are from tanks.

Consequently, UT had a large data set of tank measurements, and although not all the tanks were measured, this would not prevent them from using the measurements they did make to calculate emission factors (average emission rates). That's how the pneumatic device data were used – not all the pneumatic devices at sites were measured, but the UT team still used those data to calculate average emission factors. And although tank emissions can be highly variable due to unpredictable events, that's just as true for the pneumatic devices, and makes the use of real data all the more important.

Furthermore, the UT team could have also used their tank data to evaluate current tank models, which would have been a valuable research topic on its own.

In summary, UT collected substantial data on tank emissions during Phase I (Allen et al. 2013) but didn't use it, even though this data set might be one of the most extensive data sets available for tank emissions. It's clear that tank models don't work well and that tanks might by far be the most dominant source of methane emissions at well sites. At the same time, all indications are that the BHFS was experiencing widespread sensor failure while used by the UT

team to make these measurements, and it seems likely that the UT team would have encountered tank emissions large enough that this sensor failure would be obvious.

Additionally, in an August 11, 2014 email, Dave Allen stated the following to me:

Note that the tanks data were included in the data set for completeness and transparency, but since we did not analyze them, they did not go through the same level of quality assurance as the other data. We do not suggest using those data in any analyses.

I was surprised for him to say that for two reasons. First, even though they didn't use the data for calculating their national emission inventory, they did publish it, and without any qualification – nothing in Allen et al. (2013) suggests any problems with the tank data. Second, Dave Allen knew I had been working with his data set for almost a year at that point, and this is the first time he'd ever said anything about not using the tank data.

Unfortunately, the UT teams' reluctance to use their tank data, followed by Dave Allen's insistence that the UT Phase I tank data should not be used for any purpose, raises the question of whether he and his team knew that the BHFS was underreporting tank emission rates during their Phase I measurement program before they published those data in September of 2013. If so, the implications are:

- 1) Dr. Allen published data on tank emissions that he knew were too low.
- 2) Dr. Allen has known since 2013 that the BHFS underreports tank emissions. Even if they didn't understand at that time that the problem was sensor transition failure, Dave Allen should have reported the problem to the EPA since the BHFS is specified as a measurement method for tanks under EPA Subpart W for transmission sites, and he was chair of the EPA Science Advisory Board at the time.
- 3) Once I reported to Dr. Allen (initially in October of 2013) that I had seen sensor failure in the BHFS that caused the sampler to underreport emissions, and that it seemed clear this problem had affected his Phase I (Allen et al. 2013) data, he and Matt Harrison would have immediately recognized that this same problem was the cause of underreporting in their tank data. In that case, they've known since at least October 2013 that I was correct that the BHFS sensor failure affected their data set and that problems with the BHFS are in fact widespread, but have tried continuously to cover it up.

If they knew the BHFS was underreporting tank emissions, this problem might have been discussed – even in emails – by several people throughout the project, especially when the problem was first noticed. If UT did know early on that there were problems with the BHFS underreporting tank emissions, there might be sufficient evidence to establish that fact.

#### **APPENDIX F. Seven States Pushing EPA to Review Methane Emissions**

In December 2012, New York Attorney General Eric T. Schneiderman and a coalition of seven states (CT, DE, MD, MA, NY, RI and VT) notified the EPA of their intent to sue the EPA for failing to address methane emissions from the oil and gas industry (NY AG 2012), as these emissions contribute substantially to climate change. Schneiderman noted that rules must cover all existing sources, not just new wells, and that affordable methods for controlling methane emissions are available.

In January 2015, Attorney General Schneiderman issued a follow-up press release applauding EPA's decision to address methane emissions from new wells, again noting that the EPA must also act on existing wells and on-site equipment, which account for the vast majority of emissions (NY AG 2015). Attorney General Schneiderman's coalition filed comments on EPA white papers advocating for the direct regulation of methane from both new and existing oil and gas development and delivery equipment, and held the filing of its lawsuit in abeyance pending EPA's actions.

In December 2015, Mr. Schneiderman and attorneys general from Massachusetts, Oregon, Rhode Island and Vermont filed a notice with EPA, again urging the EPA to cover methane emissions from existing (not just new) oil and gas equipment, asserting that the Clean Air Act requires EPA to regulate these emissions (Schneiderman et al. 2015).

In March 2016, in conjunction with a meeting between President Obama and Canadian Prime Minister Justin Trudeau discussing how to reduce methane emissions, the EPA announced it would limit emissions from *existing* oil and gas facilities (Page 2016). EPA Administrator Gina McCarthy said the agency will start work immediately on the rules, with the first step being to ensure that data on methane emissions are accurate. McCarthy noted that the oil and gas sector is "complex, with hundreds of thousands" of emissions sources.

In April 2016, a coalition of 12 mayors from across the U.S., including Chicago, Los Angeles, Denver and New York, asked President Obama to address the issue of leaking methane from existing oil and gas production sites (Garcetti et al. 2016).

# APPENDIX G. Letter of Support for Touché Howard from Dr. Robert Howarth



Department of Ecology and Evolutionary Biology

February 8, 2016

To whom it may concern:

As an expert on methane emissions from the oil and gas industry, I write to endorse the findings of Touche Howard as laid out in two peer-reviewed papers he published in 2015:

Howard T, Ferrarab TW, Townsend-Small A. Sensor transition failure in the high flow sampler: Implications for methane emission inventories of natural gas infrastructure. *J Air Waste Manag Assoc.* 2015; 65: 856-652.

Howard T. University of Texas study underestimates national methane emissions inventory at natural gas production sites due to instrument sensor failure. *Energy Sci Eng.* 2015; first published online: 4 Aug 2015, DOI: 10.1002/ese3.81

These papers are written with great care and precision. I have prominently cited both in my review paper also published in 2015:

Howarth, R.W. 2015. Perspectives on air emissions of methane and climatic warming risk from hydraulic fracturing and shale-gas development: Implications for policy. *Energy & Emission Control Technologies* 3: 45-54.

I have extensive experience in assessing the quality and reliability of scientific papers, shown in part by my 22 years of experience as Editor-in-Chief of two peer-reviewed journals, *Biogeochemistry* and *Limnology & Oceanography*. Please feel free to contact me for further information on my background or on my evaluation of the work of Touche Howard.

Sincerely,

Robert W. Howarth, Ph.D.

David R. Atkinson Professor of Ecology and Environmental Biology

Robors W. Howard

E309 Corson Hall Cornell University Ithaca, NY, 14853 USA Tel: 607-255-6175 e.mail: howarth@cornell.edu http://www.eeb.cornell.edu/howarth/

# Appendix H. Vita of Touché Howard

#### Touché Howard

#### Education

B.S. Chemical Engineering, University of Idaho, 1984.

M.S. Environmental Engineering, Washington State University, 1991. Specialization in air pollution emissions and transport.

### Experience

Special Projects Manager, Indaco, Inc. Pullman, WA/ Fayetteville, NC/Durham, NC (1988 – present)

Mr. Howard is the inventor of the Hi-Flow Sampler (US Patent RE37,403) and the developer of the Vent-Bag<sup>M</sup>, both of which are used to measure natural gas s leak rates and are measurement methods approved under the EPA Mandatory Reporting Rule (MRR) for Greenhouse Gases for natural gas compressor stations and tanks. Mr. Howard has also served as a project manager and trainer for fugitive emission measurement and management programs since 1989. In this capacity, he has conducted measurement and training programs at over five hundred natural gas facilities throughout North America, Europe, and the Former Soviet Union. He has also assisted clients in submitting comments to the EPA during rulemaking periods. Mr. Howard recently provided instrumentation, training, field measurements, and analysis for a nationwide methane emissions measurement program focused on above and below ground leakage from natural gas distribution systems. Representative projects include:

- Nationwide leak measurements at natural gas distribution systems conducted in cooperation with 15 natural gas distribution companies (Sponsor: Environmental Defense Fund/Private Clients).
- Leak measurements from abandoned oil and gas wells (Sponsor: Environmental Defense Fund)
- Leak measurements at over 200 natural gas compressor stations in the United States (Sponsors: US EPA/GRI/Private Clients).
- Measurement of trends in leak rates at natural gas compressor stations and metering and regulating stations (Sponsors: PRCI/GRI/US EPA).
- Leak measurements and training using the Hi-Flow sampler at natural gas compressor stations and metering and regulating stations in Russia (Sponsor: US EPA and private clients).
- Leak measurements and training using the Hi-Flow sampler at natural gas compressor stations and metering and regulating stations in Ukraine (Sponsors: US DOE, US AID, and private clients).
- Leak measurements and training using the Hi-Flow sampler at metering and regulating stations in Ukraine (Sponsors: Private Clients).
- Leak measurements and training at natural gas compressor stations and from underground pipelines in Kyrgyzstan, Kazakhstan, and Uzbekistan (Sponsor: European Commission).

- Development of a unified leak measurement data base integrating data from six different companies with over 7000 measurements from approximately 100 sites (Sponsor: Private clients).
- Fugitive air emissions measurements from over fifty Arctic oil production facilities (Sponsors: BP/ARCO).
- Risk evaluation of sour gas well head accidents using field tracer techniques (Sponsor: Energy Resources Conservation Board, Alberta, Canada)
- Evaluation of chemical emission models for area sources using field tracer techniques (Sponsor: American Petroleum Institute).
- Preparation of monitoring plans for EPA GHG MRR programs.
- Quality assurance reviews of EPA MRR leak measurement data.

#### Research Assistant

Lab for Atmospheric Research, Washington State University – Pullman, WA (1984 – 1987)

- Operation of WSU Clean Air Facility at Palmer Station, Antarctica for a one year period monitoring remote greenhouse gases and ozone depleting chemicals.
- Development of SF6 measurement instrumentation
- Assisted in building ventilation studies, wind tunnel simulations, and dispersion measurements at Arctic oil facilities.
- Measurement of emissions from refinery wastewater facilities.

### Patents, Licenses, and Certifications

- US Patent RE37,403 "A High Flow Sampler for Leak Measurements at Process Components"
- Registered professional engineer (1993-2012)
- Firefighter I and II (State of North Carolina, NFPA 1001 1997)
- Rescue Technician NFPA 1006
- Emergency Medical Technician Intermediate (State of North Carolina)
- Hazardous Material Technician Level II (NFPA 472 1997)
- Swift Water Rescue Technician -- Advanced (NFPA 1670)
- Urban Search and Rescue -- Structural Collapse Rescue Technician

### **Publications and Presentations**

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Song, L. 2016. "Is the IOGCC, Created by Congress in 1935, Now a Secret Oil and Gas Lobby?" InsideClimate News, April 11. <a href="http://insideclimatenews.org/news/07042016/iogcc-secret-oil-gas-lobby-interstate-compact-congress-fracking-halliburton-loophole.">http://insideclimatenews.org/news/07042016/iogcc-secret-oil-gas-lobby-interstate-compact-congress-fracking-halliburton-loophole.</a>

Song, L. and K. Bagley. 2015. "EDF Sparks Mistrust, and Admiration, with Its Methane Research." InsideClimate News, April 8. <a href="http://insideclimatenews.org/news/07042015/edf-sparks-mistrust-and-admiration-its-methane-leaks-research-natural-gas-fracking-climate-change">http://insideclimatenews.org/news/07042015/edf-sparks-mistrust-and-admiration-its-methane-leaks-research-natural-gas-fracking-climate-change</a>.

UN CDM (United Nations Framework Convention on Climate Change Clean Development Mechanism). 2009. "Approved baseline methodology AM0023: Leak reduction from natural gas pipeline compressor or gate stations" (Version 3). Accessed 10 September 2015. https://cdm.unfccc.int/EB/050/eb50\_repan04.pdf.

USCFR (United States Code of Federal Regulations). 2014. 40 CFR Part 98, subpart W. Accessed 11 May 2015. <a href="http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98">http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98</a> main 02.tpl.

US Patent RE37,403 – "A High Flow Sampler for Leak Measurements at Process Components." <a href="http://patft.uspto.gov/netacgi/nph-">http://patft.uspto.gov/netacgi/nph-</a>

Parser?Sect1=PTO1&Sect2=HITOFF&d=PALL&p=1&u=%2Fnetahtml%2FPTO%2Fsrchnum.htm&r=1&f=G&l=50&s1=RE37,403.PN.&OS=PN/RE37,403&RS=PN/RE37,403.

Vaidyanathan, G. 2015. "Methane Leaks from Oil and Gas Wells Now Top Polluters." Scientific American. <a href="http://www.scientificamerican.com/article/methane-leaks-from-oil-and-gas-wells-now-top-polluters/">http://www.scientificamerican.com/article/methane-leaks-from-oil-and-gas-wells-now-top-polluters/</a> Reprinted from ClimateWire.

Wines, M. 2013. "Gas Leaks in Fracking Disputed in Study." New York Times, September 16. <a href="http://www.nytimes.com/2013/09/17/us/gas-leaks-in-fracking-less-than-estimated.html">http://www.nytimes.com/2013/09/17/us/gas-leaks-in-fracking-less-than-estimated.html</a>.

To: Gunning, Paul[Gunning.Paul@epa.gov]

From: Weitz, Melissa

Sent: Mon 10/30/2017 3:24:38 PM Subject: FW: An important concern

From: Touche Howard [mailto:touche.howard@indacoaqs.com]

Sent: Thursday, October 26, 2017 3:11 PM To: Weitz, Melissa <Weitz.Melissa@epa.gov>

Subject: An important concern

Dear Melissa -

While at the Star conference today I was told that your former EPA colleague, Alexis McKittrick, told a number of people at the GHG Inventory Workshop in June that "Touché is just seeking attention."

This is obviously very damaging for several reasons. Even though Alexis is no longer with EPA, it's widely known that I met with you and her about my concerns with the high flow and the UT studies, and consequently her statements would be seen as representing the agency's view. Additionally, she was speaking to people at a workshop who most need to understand the issues that I have raised.

As you can imagine, her comments make it very hard for me to believe that EPA ever had any intention of addressing these problems.

It would be helpful for me to know if there were ever any follow up discussions or action within EPA regarding my concerns. Additionally, I would like to know if representatives of either EDF or the UT team contacted you after we met to discuss these issues further without my input.

Given these additional concerns, I am going to revise my presentation for tomorrow to reflect the need to be more direct about these issues. I will send that to you later this evening.

ED 001785B 00000618-00001

I believe we will need to meet again to discuss these and additional issues that have arisen since
we last met. I hope that in spite of Alexis's misguided comments that there is some way to move
forward to address what is now a crisis in integrity and accuracy of information being provided
to EPA, and how EPA has addressed these problems.

Please forward this email to Alexis.

Regards,

Touché

From: Weitz, Melissa

DCRoomWJCS4228AOAP/DC-OAR-OAP Location:

Importance: Normal

Subject: meeting on Hi-Flo Sampler with Touche Howard

**Start Date/Time:** Fri 2/5/2016 6:30:00 PM End Date/Time: Fri 2/5/2016 7:30:00 PM

Call in Ex. 6 - Personal Privacy Code Ex. 6 - Personal Privacy

A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

From: Fernandez, Roger

**Location:** By phone - see call in number

Importance: Normal

Subject: Hi-Flow Sampler Issues - How it relates to Subpart W and Possibly Quad O

**Start Date/Time:** Wed 10/1/2014 8:00:00 PM **End Date/Time:** Wed 10/1/2014 8:30:00 PM

Hello Everyone,

This meeting request is a follow up to a call I had with Mr. Touche Howard and Mr. Thomas Ferrara regarding their experience with the Hi-flow sampler and some potential measurement issues associated with it.

As they noted, their primary concern is that this may result in important safety, measurement and environmental issues. They believe that this could be solved by users updating their firmware and conducting daily calibrations (as opposed to just bump tests).

Ex. 5 - Deliberative Process				
	Ex. 5 - Deliberative Process	suggest		
we have this discussion.				
Please use the following call in number:				
Dial: Conf Code:	Ex. 6 - Personal Privacy			

THANKS!!

To: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Fernandez,

Roger[Fernandez.Roger@epa.gov]

Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]

From: McKittrick, Alexis
Sent: Fri 9/26/2014 6:37:45 PM

Subject: RE: Hi-Flow Sampler Issues - How it relates to Subpart W and Possibly Quad O

I'll be able to attend. -Alexis

From: DeFigueiredo, Mark

Sent: Friday, September 26, 2014 2:06 PM

To: Fernandez, Roger

Cc: Weitz, Melissa; McKittrick, Alexis

Subject: RE: Hi-Flow Sampler Issues - How it relates to Subpart W and Possibly Quad O

Hi Roger – Melissa and I have a meeting at API that ends at 4, so I'm not sure we'll be able to make it back in time. I forwarded the scheduler to Alexis (who would be good to have at the meeting regardless of my attendance); I'll see if she can cover for the Subpart W team.

Thanks, Mark

--

Mark de Figueiredo, J.D., Ph.D. Climate Change Division U.S. Environmental Protection Agency

Office: (202) 343-9928 Mobile: (202) 251-4951

Email: defigueiredo.mark@epa.gov

----Original Appointment-----From: Fernandez, Roger

Sent: Friday, September 19, 2014 10:52 AM

To: Fernandez, Roger; Thoma, Eben; DeFigueiredo, Mark; Weitz, Melissa; Touché Howard; Johnson,

Steffan; Ferrara, Thomas

Cc: Frantz, Chris; Waltzer, Suzanne

Subject: Hi-Flow Sampler Issues - How it relates to Subpart W and Possibly Quad O

When: Wednesday, October 01, 2014 4:00 PM-4:30 PM (UTC-05:00) Eastern Time (US & Canada).

Where: By phone - see call in number

Hello Everyone,

This meeting request is a follow up to a call I had with Mr. Touche Howard and Mr. Thomas Ferrara regarding their experience with the Hi-flow sampler and some potential measurement issues associated with it.

As they noted, their primary concern is that this may result in important safety, measurement and environmental issues. They believe that this could be solved by users updating their firmware and conducting daily calibrations (as opposed to just bump tests).

Ex. 5 - Deliberative Process				
	Ex. 5 - Deliberative Process	I suggest we have this		
	discussion.			

ED 001785D 00001533-00001

Please use the following call in number:

Dial: Ex. 6 - Personal Privacy

THANKS!!

ED\_001785D\_00001533-00002

To: Weitz, Melissa[Weitz.Melissa@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]

Cc: Brian K Lamb (blamb@wsu.edu)[blamb@wsu.edu]; Tom Ferrara

(tferrara@craworld.com)[tferrara@craworld.com]; Touche' Howard

(touche howard@earthlink.net)[touche howard@earthlink.net]; Steve Edburg[sedburg@wsu.edu];

Lacey, Pam (PLacey@aga.org)[PLacey@aga.org]; Robert Harriss[rharriss@edf.org];

rgoodman@SempraUtilities.com[rgoodman@SempraUtilities.com]; 'CHumphrey@semprautilities.com'[CHumphrey@semprautilities.com];

'SAhmed3@semprautilities.com'[SAhmed3@semprautilities.com]

From: Drew Nelson

Sent: Thur 11/14/2013 8:19:24 PM Subject: RE: Follow up item from today's call

Thanks Melissa, and thanks again to you and Suzie to take the time to talk to the team today. I've copied the folks who were on the call today in case they have any follow-up questions for you or Suzie.

Drew

From: Weitz, Melissa [mailto:Weitz.Melissa@epa.gov]

Sent: Thursday, November 14, 2013 1:15 PM

To: Drew Nelson Cc: Waltzer, Suzanne

Subject: Follow up item from today's call

Hi Drew,

The information requested on today's call (inventory time series for distribution potential and net emissions, and Gas STAR reductions) is available at the following link:

http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

At the bottom of the page is a link to the full time series of the inventory tables--

ED 001785D 00001559-00001

<u>CSV Inventory Annex Tables (Zip)</u> (315 KB) - Tables from the 1990-2011 Greenhouse Gas Inventory Report Annex, in comma separated values (CSV) format.

The most relevant table will be A-137. Please let me know if there are follow up questions on the inventory files.

Thanks!

Melissa

This e-mail and any attachments may contain confidential and privileged information. If you are not the intended recipient, please notify the sender immediately by return e-mail, delete this e-mail and destroy any copies. Any dissemination or use of this information by a person other than the intended recipient is unauthorized and may be illegal.

To: Weitz, Melissa[Weitz.Melissa@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov];

Gunning, Paul[Gunning.Paul@epa.gov]; Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Irving,

Bill[Irving.Bill@epa.gov]; Banks, Julius[Banks.Julius@epa.gov]; Waltzer,

Suzanne[Waltzer.Suzanne@epa.gov]; Franklin, Pamela[Franklin.Pamela@epa.gov]

From: DeLuca, Isabel

**Sent:** Wed 6/8/2016 7:04:58 PM

Subject: RE: ACTION: Wash Post RE: methane complaint

Thanks!

From: Weitz, Melissa

Sent: Wednesday, June 08, 2016 2:52 PM

To: DeFigueiredo, Mark < DeFigueiredo. Mark@epa.gov>; DeLuca, Isabel

<DeLuca.Isabel@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; Kocchi, Suzanne

<Kocchi.Suzanne@epa.gov>; Irving, Bill <Irving.Bill@epa.gov>; Banks, Julius

<Banks.Julius@epa.gov>; Waltzer, Suzanne <Waltzer.Suzanne@epa.gov>; Franklin, Pamela

<Franklin.Pamela@epa.gov>

Subject: RE: ACTION: Wash Post RE: methane complaint

# Ex. 5 - Deliberative Process

From: DeFigueiredo, Mark

Sent: Wednesday, June 08, 2016 2:31 PM

**To:** DeLuca, Isabel <<u>DeLuca.Isabel@epa.gov</u>>; Gunning, Paul <<u>Gunning.Paul@epa.gov</u>>; Kocchi, Suzanne <<u>Kocchi.Suzanne@epa.gov</u>>; Weitz, Melissa <<u>Weitz.Melissa@epa.gov</u>>; Irving, Bill <<u>Irving.Bill@epa.gov</u>>; Banks, Julius <<u>Banks.Julius@epa.gov</u>>; Waltzer, Suzanne

<<u>Waltzer.Suzanne@epa.gov</u>>; Franklin, Pamela <<u>Franklin.Pamela@epa.gov</u>>

Subject: RE: ACTION: Wash Post RE: methane complaint

I just spoke with Melissa about adding a sentence to the Inventory paragraph about how the

ED 001785D 00001958-00001

# Ex. 5 - Deliberative Process

From: DeLuca, Isabel

Sent: Wednesday, June 08, 2016 2:10 PM

To: Gunning, Paul < Gunning.Paul@epa.gov >; Kocchi, Suzanne < Kocchi.Suzanne@epa.gov >;

Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark

<DeFigueiredo.Mark@epa.gov>; Irving, Bill <Irving.Bill@epa.gov>; Banks, Julius

< Banks.Julius@epa.gov>; Waltzer, Suzanne < Waltzer.Suzanne@epa.gov>; Franklin, Pamela

<Franklin.Pamela@epa.gov>

Subject: RE: ACTION: Wash Post RE: methane complaint

And here is the draft statement for WaPo. OAQPS is hoping to send this in an hour, so if you have any edits or concerns with the statement, please let me know asap.

EPA is reviewing the complaint.

# Ex. 5 - Deliberative Process

ED\_001785D\_00001958-00002

# Ex. 5 - Deliberative Process

From: DeLuca, Isabel

Sent: Wednesday, June 08, 2016 2:07 PM

To: Gunning, Paul < Gunning.Paul@epa.gov >; Kocchi, Suzanne < Kocchi.Suzanne@epa.gov >;

Weitz, Melissa < Weitz Melissa@epa.gov >; DeFigueiredo, Mark

<DeFigueiredo.Mark@epa.gov>; Irving, Bill <Irving.Bill@epa.gov>; Banks, Julius

<Banks.Julius@epa.gov>; Waltzer, Suzanne <Waltzer.Suzanne@epa.gov>; Franklin, Pamela

<Franklin.Pamela@epa.gov>

Subject: FW: ACTION: Wash Post RE: methane complaint

Importance: High

Touche Howard, along with the group NC Warn, has filed a complaint to EPA's OIG that saying that EPA is grossly underestimating methane emissions from natural gas production sites. The complaint claims that EPA has been wasteful with resources by using flawed studies that rely on data from Bacharach High-Flow samplers, and asks the OIG to investigate. A PDF of the complaint is attached.

Washington Post has asked EPA to comment, and OAQPS is working up a generic statement

ED\_001785D\_00001958-00003

# Ex. 5 - Deliberative Process

I'll send the draft response to WaPo for your review once it's drafted.

Thanks,

Isabel

From: Jones, Enesta

Sent: Wednesday, June 08, 2016 1:08 PM

To: Drinkard, Andrea < Drinkard. Andrea@epa.gov >; DeLuca, Isabel < DeLuca. Isabel@epa.gov >;

Davis, Alison < <u>Davis.Alison@epa.gov</u>>
Cc: Jones, Enesta < Jones.Enesta@epa.gov>

Subject: ACTION: Wash Post RE: methane complaint

Reporter: Darryl Fears

Hard DDL: 2:30 p.m. today

I'm looking into a story based a report on a complaint filed by a group called NC Warn against EPA regarding underreporting of Methane emissions, particularly at natural gas production sites. Can you guide me to the right person to speak with about this?

The complaint is centered on a device to detect emissions that malfunctions, according to NC Warn and Touche Howard, the person who developed the software that inspired it. NC Warn and Howard say the use of the device undermines the findings of the study by the former head of an EPA Science Advisory Council that said levels of methane emissions at natural gas sites are safe. NC Warn is a small group, but this complaint, supported by Howard, seems to have weight.

To: McKittrick, Alexis[McKittrick.Alexis@epa.gov] Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]

From: DeLuca, Isabel

Wed 2/10/2016 10:27:07 PM Sent:

Subject: RE: EPA Presentation Regarding Bacharach Sampler Sensor Failure

My goodness. Yes, let's chat tomorrow.

From: McKittrick, Alexis

Sent: Wednesday, February 10, 2016 5:06 PM To: DeLuca, Isabel < DeLuca. Isabel@epa.gov> Cc: Weitz, Melissa < Weitz. Melissa @epa.gov>

Subject: Fwd: EPA Presentation Regarding Bacharach Sampler Sensor Failure

Isabel,

Please see the follow up email from Touché Howard below. Ex. 5 - Deliberative Process

## Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

Are you in tomorrow? Maybe you, me and

Melissa could sit down for a few minutes and discuss?

Thanks,

Alexis

Sent from my iPhone

Begin forwarded message:

From: Touche Howard < touche.howard@indacoaqs.com >

Date: February 9, 2016 at 10:37:50 PM EST

To: "Weitz, Melissa" < weitz.melissa@epa.gov >, McKittrick.alexis@epa.gov Subject: EPA Presentation Regarding Bacharach Sampler Sensor Failure

Melissa/Alexis --

Thanks for setting up the meeting last Friday regarding the issues with the Bacharach Hi-Flow Sampler. I just wanted to make a couple of observations.

ED\_001785D\_00002877-00001

I think the delays in starting the meeting could have been avoided if we had met ahead of the meeting, which is why I arrived 45 minutes before the scheduled start time. We had discussed me arriving early to get things set-up, so I was surprised to be turned away and told to come back ten minutes before the start time. As a result, by the time we got through security, it was time for the meeting to start.

My intent for being early was to be able to provide you a brief overview of what would be discussed and who I had invited to call in, as well as to get the presentation set up. Unfortunately, we didn't have time to do those things, resulting in delays because you had to find a press office person since a reporter had been invited and it also took the same amount of time to set up the computers.

Additionally, there were repeated problems with the computer as it stalled about a third of the way through, and then shut down completely about two thirds of the way through the presentation. Those events were significant distractions, both to me as a presenter as well as to the audience, since they could no longer see the presentation.

Ironically, I was cautioned prior to the meeting that sometimes problems are rigged into presentations when discussing topics that are uncomfortable for agencies. I don't think that's the case here, but you can see how the problems that occurred could feed into people's suspicions. However, I do think these problems were a result of this meeting not being a very high priority for you.

Well, that's understandable since you have a thousand things coming at you every day. But I think it would be very unfair to both of you if this slipped under your radar when it's such a critical issue, only to have it come back to haunt you later. Perhaps the first people at EPA to hear about the Volkswagen issues and the Flint water crisis were swamped as well and just didn't realize the importance of those problems until it was too late.

So I want to emphasize that the issues that I've raised really do have broad implications, and as such, they may get a lot of scrutiny. And in particular, given all that's led up to where we are now, how EPA handles these issues may in particular get a lots of attention.

Also, I have a follow-up question for Alexis based on our conversation at the EPA conference in Pittsburgh. When I initially raised some of these issues to you then, your reply was that I should be cautious because people might go after my work. That's a pretty unusual response from an EPA person, so I assume that someone discussed these issues with you before I did and specifically told you that they would retaliate. If that's the case, I would like to know who that was, because that's an unacceptable response to these problems.

It's very important that you understand that the environmental, health, and -- especially -- safety issues far outweigh any concerns I might have about being retaliated against. Certainly we hope the occurrence of an explosion or fire is a remote possibility due to Hi-Flow sensor failure, but there's no excuse for exposing people to any risk of a preventable tragedy,

I'll acknowledge that my concerns are probably heightened by the last twelve years I've spent as a professional firefighter. I'm lucky, in the sense that I've spent my entire career at our busiest station, but that also means I've seen a lot of bad things happen to people. Dragging a body out of a fire and feeling their burnt flesh come off on your turnout gear is a terrible experience. But what's worse -- far worse -- is hearing the screams of agony when someone has been badly burned but survived.

Honestly, I wouldn't think it would take those type of experiences for anyone to realize the importance of disclosing the sensor failure issue as rapidly as possible. Unfortunately, however, here we are, over two years later, and almost no progress on this problem has been made.

You two might be the last chance for this to be addressed.
Regards,
Touche'

To: DeLuca, lsabel[DeLuca.lsabel@epa.gov]
Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]

From: McKittrick, Alexis
Sent: Fri 2/5/2016 6:58:30 PM

Subject: Fwd: meeting on Hi-Flo Sampler with Touche Howard

This is what I sent. Didn't mean to include the bit at the bottom.

Sent from my iPhone

Begin forwarded message:

From: "McKittrick, Alexis" < McKittrick. Alexis@epa.gov>

Date: February 5, 2016 at 1:56:18 PM EST

**To:** "ralvarez@edf.org" <ralvarez@edf.org>, "lisa.song@insideclimatenews.org" lisa.song@insideclimatenews.org>, "nancy@ncwarn.org" <nancy@ncwarn.org>,

"terri.shires@aecom.com" < terri.shires@aecom.com>

Subject: Fwd: meeting on Hi-Flo Sampler with Touche Howard

Sent from my iPhone

https://epawebconferencing.acms.com Ex. 6 - Personal Privacy

From: Weitz, Melissa

Sent: Wednesday, December 23, 2015 4:35 PM

**To:** Weitz, Melissa; DeFigueiredo, Mark; Waltzer, Suzanne; McKittrick, Alexis; Macpherson, Alex; Moore, Bruce; Thoma, Eben; Thompson, Lisa; Hambrick, Amy; Banks, Julius; Irving, Bill

Cc: Howard, Jodi

Subject: meeting on Hi-Flo Sampler with Touche Howard

When: Friday, February 5, 2016 1:30 PM-2:30 PM. Where: DCRoomWJCS4228AOAP/DC-OAR-OAP

Call in Ex. 6 - Personal Privacy Code Ex. 6 - Personal Privacy

A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

To: DeLuca, lsabel[DeLuca.lsabel@epa.gov]

Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]; Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Irving,

Bill[Irving.Bill@epa.gov]

From: McKittrick, Alexis

Sent: Fri 2/5/2016 6:39:23 PM

Subject: Need you ASAP in 4228A

Touche Howard invited press reporters to 1:30PM call.

Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

Alexis McKittrick, Ph.D.

Climate Change Division

U.S. Environmental Protection Agency

Phone: 202-343-9153

E-mail: mckittrick.alexis@epa.gov

To: Weitz, Melissa[Weitz.Melissa@epa.gov]

**Cc:** DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]

From: McKittrick, Alexis MW
Sent: Fri 6/10/2016 6:04:45 PM

Subject: Touche Howard in Washington Post

Melissa,

In case you haven't already seen this (but I'm guessing you have):

 $\frac{https://www.washingtonpost.com/news/energy-environment/wp/2016/06/09/this-heated-fight-over-methane-emissions-is-almost-as-hot-as-the-gas/$ 

I left you a voicemail on this topic. Give me a call when you get a chance.

Best,

Alexis

Alexis McKittrick, Ph.D.

Research Staff Member

Institute for Defense Analyses

Science and Technology Policy Institute

1899 Pennsylvania Ave. NW, Suite 520

Washington, DC 20006

(202) 419-5412

amckittr@ida.org

To: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]

Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]

From: McKittrick, Alexis

**Sent:** Tue 12/15/2015 5:58:21 PM

Subject: FW: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

FYI

From: Touche Howard [mailto:touche.howard@indacoags.com]

Sent: Tuesday, December 15, 2015 12:48 PM

To: allen@che.utexas.edu

Cc: McKittrick, Alexis <McKittrick.Alexis@epa.gov>; terri\_shires@aecom.com; Weitz, Melissa <Weitz.Melissa@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; McCabe, Janet <McCabe.Janet@epa.gov>; RAlvarez@edf.org; shamburg@edf.org; Fernandez, Roger <Fernandez.Roger@epa.gov>; rharriss@edf.org; ritterk@api.org; dnelson@edf.org; sedlakoffice@est.acs.org; dmccabe@catf.us; dlyon@edf.org; Maxwell, Dave (Austin) <dave.maxwell@aecom.com>; dschroeder@catf.us; dzavala@edf.org; Chuck Kolb <kolb@aerodyne.com>; Gamas, Julia <Gamas.Julia@epa.gov>; linda.lee@arb.ca.gov; bmordick@nrdc.org; amrowka@arb.ca.gov; casey.pickering@erg.com; Wisetiawa@arb.ca.gov; Smith, James-D <Smith.James-D@epa.gov>; Snyder, Jennifer <Snyder.Jennifer@epa.gov>; michael.ege@tceq.texas.gov; paige.sprague@tceq.texas.gov; adam.pacsi@chevron.com; Rees, Jeff <Jeff.Rees@pxd.com>; matt.harrison@aecom.com; alr@andrew.cmu.edu; awilcox@harcresearch.org; andres.restrepo@sierraclub.org; gabrielle.petron@noaa.gov; natalie.spiegel@sierraclub.org; nathan.matthews@sierraclub.org; rsawyer@me.berkeley.edu; Ganapathy, Roopa (EC/EC) <Roopa.Ganapathy@canada.ca>; vgowrishankar@nrdc.org; dan.hill@pe.tamu.edu; Matthew.Fraser@asu.edu; seinfeld@caltech.edu Subject: Re: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

### Dave --

Just to follow up on the safety issue, I did a news media search to see what the current state of natural gas industry safety is, because if fires and explosions have been eliminated over time, then my fears would be groundless. But, it turned out to be much worse than I expected. It looks like there have been at least 33 explosions or fires at natural gas facilities over the past five years, killing 11 people and injuring 126 others. You can't tell the cause of all these incidents from the media reports, but it's clear that it's still true that natural gas facilities can and do blow up.

So the issue of safety is still very relevant. But even if it weren't, I'm sure you and Matt would want to address this issue immediately, just for the health and environmental aspects. If nothing else, I believe companies can start their 2016 Subpart W reporting measurements in January, and since two reporting years have gone by since this problem came to light, I think we can all agree that we don't want to let another year go by that could be affected by Hi-Flow sensor failure.

nnks,
ache'
Mon, Dec 14, 2015 at 4:42 PM, Touche Howard < touche.howard@indacoaqs.com > wrote:
Dave
Mon, Dec 14, 2015 at 4:42 PM, Touche Howard < touche.howard@indacoaqs.com > wrote

I think that Matt's statement of "I see no safety issue" (regarding the Bacharach Hi-Flow sampler's problem of reporting leaks as far smaler than they actually are) might have resulted from your team either not being aware of all the potential uses of the Hi-Flow sampler or from having a somewhat narrow view of what problems can compromise safety.

Probably half of the leak measurement programs I've conducted were for private companies whose primary goals were to reduce gas loss and to improve safety, as opposed to cataloging greenhouse gas emissions. At 1 to 2% of all the facilities I've been to, we found leaks that caused the operators to immediately shut down equipment. Examples include leakage into compressor distance pieces that was large enough to cause back pressure into the engine crankcase, flanges that had a leak rate large enough that it might cause further gasket erosion and failure, and large leaks at welds on compressor fuel gas systems that might catastrophically fail or be large enough to reach an ignition source due to induced sparking at vibrating components in the ignition coil area.

Did we prevent explosions in those cases? We'll never know, but we did provide one layer of defense by eliminating imminently dangerous conditions. So if only 1% of facilities have a dangerous underlying condition that might go undiscovered if a Hi-Flow sampler fails, is it really worth an hour of your time to address this issue? I think most people would say yes.

Even high flow surveys that focus on research or greenhouse gas reporting have the opportunity to reduce dangerous conditions if done properly. I think the protocol in most (hopefully all) leak measurement programs, whatever their focus, is to immediately alert facility operators of any hazardous conditions found. So it's certainly not acceptable to leave hazards unidentified due to sampler failure just because many surveys are focused on greenhouse gas emissions instead of facility integrity.

Other instances where sampler failure might affect safety are when it is used to make an on

Touche'

the spot repair decision when a leak is discovered by an operator and when it is used to survey facilities being put into initial service. And as I pointed out previously, we don't know all the ways a sampler might be used now or in the future. If, for instance, it were used to rank distribution leaks for repair, under reporting large leaks could have tragic consequences.

Now you might think that other indications, such as an IR camera, or auditory, visual, and olfactory (AVO) detection would provide clues that a leak was much larger than the sampler indicated, but most people just don't have that level of experience, and a noisy and/or hot environment can make it even more difficult. There's an excellent example of this in your Phase II pneumatic work, where Device No. XQ01-PC04 was measured both by Hi-Flow (0.13 scfh) and meter (37.37 scfh), and you assume the Hi-Flow measurement is too low due to the device not being adequately enclosed. However, this device was a continuous bleed controller with a high emission rate (in the top 20% of the continuous controllers you measured). Consequently, even though the Hi-Flow was making an easy to read steady state measurement for most of that interval, your technicians did not recognize that the Hi-Flow reading was almost 300 times too low (if they had, they would have certainly attempted to correct the problem while the measurement was being made). This highlights that even people who had been making these type of measurements day after day during an extensive field program could not accurately judge emission rates without reliable instrumentation.

And although safety systems like gas detectors or hot work permits provide one line of defense, they can't always protect the facility from a leak that could have been fixed but wasn't, and then either failed catastrophically or found an ignition source before automatic detection shut down equipment. Having been to so many facilities, I've heard lots of stories of past explosions. My favorite was was told to me by an operator who was the son of a compressor station manager. When he was growing up, they lived near the station, and one night after dinner he wanted to go to the mechanic's shop at the site to work on his car. Oh, no, his mother says, it's your turn to do the dishes. So there he is, sulking at the sink, when the station blows up, basically right in front of him as he's watching out the kitchen window, and destroying with it the mechanic's shop where he would have been if his mother hadn't made him wash dishes.

Unfortunately, not all the stories had a happy ending like that.
I hope this provides a better perspective on the safety issues involved.
The uler
Thanks,

On Wed, Dec 9, 2015 at 8:56 PM, Harrison, Matt <<u>matt.harrison@aecom.com</u>> wrote:

I see no safety issue. HiFlows are never used as safety devices to my knowledge

Matt Harrison

512-694-0572

Sent from my iPhone

On Dec 9, 2015, at 2:25 PM, "Touche Howard" < touche.howard@indacoaqs.com > wrote:

Dave --

Now that the EPA is considering using your initial EDF study at production sites (published in PNAS in 2013) and your follow-up study on pneumatic controllers (published in ES&T in 2014), it's critical that we resolve the Hi-Flow sensor failure and other quality assurance issues surrounding those studies as soon as possible. The quickest way to do that is for us to directly discuss these issues with EPA, and I think once you understand the evidence, you'll be able to see the problems immediately. To that end, let's try to get together tomorrow or Friday. (Melissa and Alexis - I can come up and meet with you either day, and if Dave can't make it, he can call in.)

My biggest concern is safety -- having an instrument that reports natural gas leaks far lower than they actually are is clearly a huge safety issue, and as long as you tell people that this problem didn't occur in your work, it will be very hard for anyone to take it seriously. Meanwhile, for you and EPA, this also represents important health and environmental concerns. And of course since you were chair of the EPA Science Advisory Board while you were conducting this research, and the Hi-Flow sampler is one of the methods approved by EPA to make measurements for their greenhouse gas reporting program under Subpart W, I'm sure you feel a special responsibility to address these issues as soon as possible.

I've attached my ESE paper outlining the problems in your initial 2013 production study as well as my letter and your response about the 2014 study. I've also attached a reply that I wrote in response to your commentary on my paper in ESE, because even though you withdrew that commentary after seeing my response, I

think my response did clarify some of the issues.

Since we unfortunately haven't had an opportunity to discuss these issues directly, I'll summarize the evidence here and what I believe are your counterpoints, based on your reviews of my paper and the commentary you submitted. I also want to allay your concerns, which you've stated to others, that I'm raising these issues because I want to sell my own samplers or services. I'm only wrapping up loose ends now, and after this I won't be working in this area any more.

The first issue is sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS), where it can fail to transition from the low range (0 to 5% gas) catalytic oxidation sensor to the high range (5 to 100% gas) thermal conductivity detector, which can cause the sampler to report large leaks as being much smaller that they are. We don't know why this happens, but there's no question that it can, because we demonstrated it in three different instruments, including yours. It doesn't seem to occur for pure methane streams, but we've seen it in the field for gas streams with methane content as high as 91% (J. Air Waste Manag. Assoc. 65:856–862. doi: 10.1080/10962247.2015.1025925).

The effect of this problem is clear in your Phase I data, which I've plotted below showing emission rate as a function of site methane composition. As you can see, most of the high emitters only show up at sites with high methane compositions, and there's no reason that should happen in the real world, especially when you consider that it occurs for several different types of sources.

<image.png>G

Now I believe your counter argument is that this phenomenon is due to air pollution control regulations reducing emissions in the Rocky Mountain region, where the methane content of the gas is lower as well. However, several things tell us that's not the cause of the trend in the figure above. First, even when you take the Rocky Mountain region out of the analysis, there's still far more high emitters at sites with higher methane content. Second, even within just the Appalachia region, the occurrence of high emitters increases dramatically over a very narrow range of site methane compositions, from 95% to 98% methane (shown below). What that tells us is that sampler can start seeing some of the high emitters once methane composition is in the range of 95%, but is still missing a lot of them until methane composition gets up to the 97 to 98% range. This is also an extremely important indicator that this problem could be occurring even for gas streams with methane content above 95%, meaning the problem could occur in all segments of the natural gas industry.

## <image.png>

Finally, your emissions measurements made by tracer technique confirm that sensor failure occurred and that the trend of emission rate vs concentration is not caused by regional differences. Now, in your comment you said you found my analysis of your tracer data complex, probably because I showed how Hi-Flow measurements got lower and lower than the tracer measurements for sites with fewer estimated emissions from sources like tanks. So I've simplified that analysis, and just removed the two sites that had 98% or more of the emissions estimated as opposed to measured. This comparison of the tracer versus on site Hi-Flow measurements is shown below.

## <image.png>

So clearly, as you've suggested, there are regional differences, assuming these sites are representative. The tracer data shows that the emissions from sites in the Rocky Mountain (RM) region are lower than the sites in the Mid-continent (MC) region, although in the same range as 75% of the Appalachia (AP) sites. But just as clearly, the sites with lower methane content (Rocky Mountain and Mid-continent, where sensor failure might occur consistently) have far lower (about a factor of two) Hi-Flow measurements than the tracer technique. Meanwhile, the sites with high methane content (Appalachia, where the problem isn't expected to occur) have Hi-Flow measurements close to or exceeding the tracer measurements. Keep in mind that because some of the on-site data comes from estimates, this masks the magnitude of the error, but at least this is a simple comparison.

Now if the variations between the tracer and the Hi-Flow were due to random experimental errors, then we'd expect roughly 50% of the sites to have tracer greater than Hi-Flow, and 50% lower. It's actually a 70/30 split, but the remarkable thing is that we can predict which region will have tracer greater than Hi-Flow and which won't. This is pretty much the same thing as me being able to walk into a bar and betting the barmaid that if I stand on her side of the bar and flip a coin it will always come up heads, but if I stand on my side of the bar and flip a coin, it will always come up tails. And in between drinks, we run that experiment, and it turns out that I'm right 16 out of 17 times.

Now that's a bar bet I'd like to be able to make routinely.

You also said in your unpublished comment to ESE that the testing I conducted on your instrument and others in March of 2013 showed a low occurrence of this problem. That's true of course, but I was surprised you said that, since you know that immediately after we did that testing that I met with some very experienced

Hi-Flow technicians who specifically told me that they had fixed some of their samplers that had been reporting leaks too low by upgrading the sampler's software. Since all of the samplers we tested when we tested yours had new generation software, the only real surprise is that we saw any failure at all, and that failure was in your sampler. So even though new software improves the problem, it doesn't fix it completely. Additionally, there are lots of these samplers around the US and the world using older software, and lots of data that has been collected using samplers prior to software upgrades.

One other argument you made was that your Phase I pneumatic data, made by Hi-Flow, was higher than your Phase II pneumatic data, collected by meter, and if your Hi-Flow had been reporting too low, this should have been the other way around. The reason this isn't true is that your Phase I pneumatic data is clearly an emitter data set (95% of them are emitting) while your Phase II data set is a comprehensive data set (about 21% are actual emitters). So you accidentally excluded sampling zero emitters in Phase I, which biases that data high by a factor of four to five, and offsets any Hi-Flow sensor failure. Additionally, the Phase II data actually shows exactly what I predicted to you it would show -- that the high emitters are more predominant at sites with lower methane compositions when measured by the inline meter as opposed to your Phase I measurements, where the sensor failure caused the high emitters at those sites to be under reported.

In any case, I think this shows that it probably would have been better to involve me directly in discussions you had with the EDF committees and others about this problem after I brought it to you in October of 2013, because I could have explained immediately why the reasons you thought this problem didn't affect your Phase I data were incorrect. It has been puzzling to me that given the overwhelming evidence, that this problem wasn't obvious to you, but I'm wondering if that might be due to inexperience with field measurements. As an example, in both your Phase I and Phase II papers, you incorrectly describe the operation of the Hi-Flow sensors, and without understanding that the Hi-Flow has to to switch back and forth between sensors to make accurate measurements, it's probably impossible for you to understand the sensor transition problem.

I'm wondering if inexperience might have also led to the problems in your Phase II work as well. It's a harsh environment for meters to be transported between field sites on rough roads and have raw natural gas run through them, and I think most people with experience in field measurements would have built in a routine testing of those meters during the project, rather than just check them before and after the project as you did. When you're out in the field looking at pneumatics, you see lots of them with oil or other hydrocarbon accumulations, so it's easy to picture how the meter sensor could get fouled, as yours did. I would think at least a weekly multi-point meter calibration and a daily single point flow check would

be required to ensure accurate measurements. which is what was done during the EDF WSU distribution work. The Indaco Hi-Flows that were used in that project have a very similar flow measurement system to your Fox meter, which is a thermal element in a tube, and even though the distribution study was a much less harsh environment, where leaks of relatively clean distribution gas were measured and the flow system dilutes those leaks with air before the gas hits the sensors, full scale weekly calibrations and single point daily flow checks were conducted.

Now, as you remember, while that project was ongoing, I found that one of your two primary meters was measuring too low by a factor of three. Well, that's not a surprise, given the harsh environment. I haven't used the particular meter that you were using before, but I did look at the manual for it, and it clearly states that a dirty sensor will cause measurements to be too low.

But I think how you addressed that issue indicates further inexperience. Since you don't mention the meter test I made showing it was a factor of three too low in your paper, but only indicate that you found the problem post project, it appears that you just kept using the meter, without trying to figure out what was wrong with it, and without instituting any additional meter checks.

Instead, it wasn't until the end of the project that you did any further checks, and at that point the response of the meter had changed again, to being low by about 34%. In order to understand more about the problem, you tried to use your Hi-Flow data to validate the meter results. Now your laboratory comparisons of the two for the most part are excellent and agree within 10%. But surprisingly, your field comparisons of the Hi-Flow to the meters are far worse. For measurements where either one or the other was >0.5 scfh, only 4 out of 19 (21%) are within 25%, and even for measurements >6 scfh, only 3 out of 10 (30%) are within 25% of each other. You do allude to the possibility of leaks affecting the measurements but don't give any indication that you tried to quantify the leaks that you think affected the measurements.

For comparison, in the WSU distribution work, where direct and tracer measurements were compared, 10 out of 14 (71%) were within 50% of each other, over a range of about 0.6 to 56 scfh. Now I would have liked that to be better, but I think I understand some of the challenges, one being that some of those that are far off are at really low emission rates, so missing just one source could throw you off a lot. But keep in mind, that's measuring the whole M&R facility or an underground leak, and comparing it to a downwind tracer flux measurement, so you have lots of challenges including multiple measurements at the facility and tracer source configurations.

But for your pneumatic work, while doing a direct comparison of Hi-Flow to meters, for just single sources, only 7 of 19 (37%) were within 50% of each other over a similar emission range of 0.5 to 60 scfh.

So unfortunately your comparison of High Flow to meters should not have been used to justify correcting your meter, especially when my direct test of that meter's performance mid-project showed it was much worse than the post project check indicated.

Another indication of the meter uncertainty came from Matt Harrison, who was present when I found that your meter was reading a factor of three too low, and said at the time, "Yeah, everyone knows that meter is flaky. You can hook it up to an pneumatic and hear the pneumatic fire but not see anything on the meter."

Now, along with the sensor getting dirty, your meter measurements might have been affected by two other factors mentioned in the meter manual. These meters are supposed to be oriented upright, and you need a certain length of straight run (I think for the meter you were using, six inches) before the meter. However, it appears, looking at a slide from the presentation about the project on your website shown below, that those conditions weren't met either. Although you can see in the close up that the meter is marked with a label that says "Keep Upright and Level", that condition hasn't been met in either configuration pictured. Additionally, the entrance length doesn't appear to meet the required distance either.

<Upside Down Meter 1.jpg>

<Upside Down Meter Close-up.jpg>

I think these issues were all compounded by perhaps your lack of experience with what information editors and reviewers need to evaluate field measurement papers. Your meter problem is only mentioned in a footnote on page 59 of your Supplementary Information, and was likely missed by the editor and reviewers. But if reviewers with substantial field experience understood the entire picture -- that you only checked your calibration before and after the project, that there was an undisclosed mid project test showing meter performance was much worse than the correction you applied, that after you were shown one meter was faulty in the middle of the project that you simply continued to use it without finding out what was wrong or instituting improved calibration checks, "that everyone knew that meter was flaky," and that your Hi-Flow and meter field measurements don't compare very well -- I believe they would conclude that you didn't meet the fundamentals of quality assurance and that the paper would have been rejected.

So unfortunately neither the Phase I or Phase II data should be used by EPA.

Although there may be large uncertainties in inventories, we shouldn't include numbers that have such large question marks. Think about cancer treatments. Those have very uncertain outcomes, but that doesn't mean that we don't want good quality assurance in cancer research or in the dosages of drugs or radiation therapy that are used. And when you consider the broad environmental impact of air toxics to the communities surrounding oil and gas facilities as well as the consequences of climate change, it's critical that we use the best data possible.

And as I said at the start, safety is my biggest concern regarding the HiFlow sensor failure, and I think perhaps again inexperience has caused you not to fully appreciate what a critical safety issue this is. I've spent a lot of time measuring leak rates at natural gas facilities, and I've seen facility personnel shut down units in order to address large leaks that we found due to safety concerns -- I've done lots of leak measurement programs that were focused more on the integrity of the facility rather than the issue of greenhouse gases. Additionally, we don't know how the sampler might be used in the future -- for instance, given GTI's and WSU's work in distribution, it might be used to rank leaks for repair in that segment (even though the WSU study used a different version of the sampler not affected by this problem).

James Reason wrote a really great book about the Swiss cheese theory of disasters (Reason, James (1997). Managing the risks of organizational accidents.

Aldershot: Ashgate. <u>ISBN 1840141042</u>.) which is widely studied in aviation, engineering, and the fire service. In it he describes how the really terrible things that happen usually occur because there have been failures on several levels, and those failures line up to let something really bad happen.

We had a terrible example of that happen here in North Carolina a couple of years ago. A couple checked into a hotel, and the next morning they were dead. Seven weeks later, an 11 year old boy died in the same room, and although his mother survived, she had permanent brain damage.

All of that could have been avoided, because they were killed by carbon monoxide. You might have seen this on 20/20:

http://abcnews.go.com/US/north-carolina-best-western-room-225-open-deaths/story?id=21564280

Here's how it all lined up:

- 1) The hotel pulled an old pool heater out of another property and installed it at that hotel, even though it was at the end of its life, meaning it was inefficient and was at risk for producing more carbon monoxide, and they didn't get a city inspection permit;
- 2) The vent pipe was corroded, and let the CO escape under the room where everyone was killed;
- 3) There were holes in the fire place in the room that let more CO in that would have come in otherwise;
- 4) The CO detectors that were supposed to have been installed in the rooms were actually natural gas detectors, installed by mistake.

So that's what killed the first couple.

But here's why the little boy died:

- 1) Three days after the couple was killed, a family in the room above got really sick, and complained, but the hotel didn't pay attention;
- 2) The family of the first couple raised warnings with the hotel and police that it might be CO and again no one paid attention;
- 3) The medical examiner didn't visit the scene of the first couple and see that the wife had thrown up (an important clue in CO poisoning)
- 4) He also didn't put an expedite order on their blood work, so it sat for 40 days (two people simultaneously dead in an enclosed space -- a huge alarm bell for some toxic substance, especially CO);
- 5) He finally got the results four days before the child died in the room, but;
- 6) He sat on them for a week and by the time he finally sent them out to the local police; the child was had been killed and his mother permanently injured.

That's a tragic story, all right. And as you can imagine, the two families are suing everyone in sight that had anything to do with any of that, and I would too if I had lost a family member. Meanwhile, the DA also charged the head of the hotel management group with three counts of manslaughter, and all of those cases are still on going.

That's just one example of how tragic things can happen when we don't do everything possible to ensure people's safety. But if you do just a little bit of research, you'll see how frighteningly common that is.

So I know you'll want to address the Hi-Flow sensor failure issue immediately.

As I suggested at the start, let's do it this week. I can go up and meet with EPA tomorrow or Friday, and if you can't be there in person, you can call in, and you can have any interested parties from EDF or your production committees call in as well. i know everyone's busy, but this won't take more than an hour, and I think we should all be willing to make that much time for such a critical issue.

Just let me know when the best time for all of you is.

Thanks,

Touche'

<Howard Energy Science and Engineering Analysis of UT Data Set 2015.pdf>

<ES&T Comment on Allen et al. Methane Emissions from Process Equipment.pdf>

<Dave Allen Response to ES&T Letter.pdf>

<Touche Response to Dave Allen Comment in ESE Submitted 09 10 2015.pdf>

To: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Bylin, Carey[Bylin.Carey@epa.gov];

DeLuca, Isabel[DeLuca.Isabel@epa.gov]

Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]

From: McKittrick, Alexis

**Sent:** Wed 7/22/2015 2:25:15 PM

Subject: RE: Inside Climate (DDL ASAP) regarding Eben Thoma

Just confirming that I have not met with them either.

Alexis

From: DeFigueiredo, Mark

**Sent:** Tuesday, July 21, 2015 5:31 PM **To:** Bylin, Carey; DeLuca, Isabel

Cc: McKittrick, Alexis; Weitz, Melissa; Waltzer, Suzanne

Subject: RE: Inside Climate (DDL ASAP) regarding Eben Thoma

Ditto - haven't met with them and I'm not aware of any meetings with them on the topic either.

-Mark

From: Bylin, Carey

Sent: Tuesday, July 21, 2015 5:30 PM

To: DeLuca, Isabel

Cc: McKittrick, Alexis; DeFigueiredo, Mark; Weitz, Melissa; Waltzer, Suzanne

Subject: Re: Inside Climate (DDL ASAP) regarding Eben Thoma

I have not. We've worked with others from Heath but I have not met (that I recall) with Jim.

Carey Bylin

On Jul 21, 2015, at 5:05 PM, DeLuca, Isabel < DeLuca. Isabel@epa.gov > wrote:

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Apologies, oil and gas team, hopefully this is a quick question. Has anyone ever met with Jim Rutherford, VP of products at Heath, or Doug Keeports, president of Bacharach Inc., regarding the Bacharach Hi-Flo-Sampler? ORD says no, and punted it back to us.

I'm guessing no one in CCD met with them, but if you have (or know of someone who has), let me know.

From: StClair, Christie

Sent: Tuesday, July 21, 2015 4:57 PM

To: DeLuca, Isabel; McMichael, Nate; Noonan, Jenny; Davis, Alison; Bremer, Kristen;

Jones, Enesta **Cc:** Lemon, Mollie

Subject: RE: Inside Climate (DDL ASAP) regarding Eben Thoma

Yes indeed. She's asking specifically if Bacharach or Heath have approached EPA about funding studies of the sampler.

ORD isn't aware of any conversations like that so deferred to you all.

## Christie St. Clair

Office of Public Affairs

Environmental Protection Agency

Washington, DC

o: 202-564-2880

m: 202-768-5780

From: DeLuca, Isabel

Sent: Tuesday, July 21, 2015 4:54 PM

To: StClair, Christie; McMichael, Nate; Noonan, Jenny; Davis, Alison; Bremer, Kristen;

Jones, Enesta **Cc:** Lemon, Mollie

Subject: RE: Inside Climate (DDL ASAP) regarding Eben Thoma

## Ex. 5 - Deliberative Process

From: StClair, Christie

Sent: Tuesday, July 21, 2015 4:33 PM

To: McMichael, Nate; Noonan, Jenny; Davis, Alison; Bremer, Kristen; DeLuca, Isabel

Subject: Inside Climate (DDL ASAP) regarding Eben Thoma

Hi all,

Inside Climate is doing a piece on the Bacharach Hi-Flo sampler, and an upcoming paper looking at what the authors say is a poor track record of measuring methane emissions.

ORD helped with a portion of the inquiry, and they are deferring the second portion to OAR. Here's the question:

Bacharach, Inc, the manufacturer of the Bacharach sampler, and Heath Consultants, the distributor of the sampler, said they've had preliminary conversations with the EPA to discuss whether EPA would be interested in helping fund additional testing of the Bacharach sampler. I've been told that Heath initiated

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the conversations. It's unclear if Bacharach, Inc. was directly involved in talking to the EPA as well.

I literally just got the referral on this portion of the question, so my apologies for the late notice. Trying to close this out today if at all possible.

Please call if this is unclear!

Christie

Christie St. Clair

Office of Public Affairs

Environmental Protection Agency

Washington, DC

o: 202-564-2880

m: 202-768-5780

From: Milbourn, Cathy

Sent: Tuesday, July 21, 2015 4:23 PM

To: StClair, Christie

Cc: Maguire, Megan; Hull, George; Jones, Enesta; Milbourn, Cathy Subject: FW: Questions from Inside Climate regarding Eben Thoma

Hi Christie:

In Enesta's absence George asked me to reach out to you since its now OAR's to answer. Megan asked me to send this back to the air program for them to review question 1 and to answer question 2. Please let me know if you have any questions. This is the inquiry that came in to you on Friday 7/17.

Thanks!

From: Maguire, Megan

Sent: Tuesday, July 21, 2015 3:47 PM

To: Milbourn, Cathy

Cc: Hubbard, Carolyn; Linkins, Samantha

Subject: RE: Questions from Inside Climate regarding Eben Thoma

Hi Cathy-

From Eben:

On question (1),

Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

Regarding (2) I don't know, it wasn't with me. There many people within EPA who could have talked with the distributor about this. Defer to OAR.

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## FROM LISA SONG THE REPORTER

Here are my questions in writing:

1. Two scientists I've spoken to--Thomas Ferrara, a consultant at Congestoga-Rovers & Associates (the company recently changed its name to GHD), and Touche Howard, an independent consultant, said that in Oct 2012, they attended a scientific meeting in Boulder. At the meeting, they met Eben Thoma of EPA. The three of them had a brief conversation. During that conversation, Mr. Thoma mentioned he'd had difficulties with the Bacharach Hi-Flow Sampler while using it to take measurements in the Bakken. Mr. Thoma's experience was documented in Modrak et al 2012, where the authors explained they thought the instrument had a response factor issue.

I'm asking Mr. Thoma to confirm:

- a) If he remembers meeting Mr. Ferrara and Mr. Howard at a conference in late 2012.
- b) If he remembers having a conversation with them where he explained he'd had difficulties with the Bacharach sampler.
- 2. Bacharach, Inc, the manufacturer of the sampler, and Heath Consultants, the distributor of the sampler, said they've had preliminary conversations with the EPA to discuss whether EPA would be interested in helping fund additional testing of the Bacharach sampler. I've been told that Heath initiated the conversations. It's unclear if Bacharach, Inc. was directly involved in talking to the EPA as well.

The person at Heath who was probably involved is Jim Rutherford, VP of products.

The person at Bacharach who would've been involved is Doug Keeports, president of Bacharach Inc.

I'm asking if the EPA can confirm that some kind of preliminary conversation took place with Heath and/or Bacharach.

Thanks! I hope to hear back by EOD Monday. If I get the name of Heath's contact at the EPA, I'll let you know right away. And feel free to ask questions if any of this is unclear.

Best,

Lisa

On Thu, Jul 9, 2015 at 4:19 PM, Jones, Enesta < Jones. Enesta@epa.gov> wrote:

Lisa,

Roger Fernandez no longer works in the Natural Gas STAR program. The October meeting that you referenced was an informal meeting for Howard to meet with EPA staff to share information with EPA – it was not a formal, public meeting (e.g. a workshop or roundtable).

In terms of improving our estimates of methane emissions at the national level, EPA continues to refine the emission estimates in the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks to reflect the most robust and up-to-date information available. Substantial amounts of new information on the oil and gas sector is becoming available from a number of channels, including studies by government, academic, and industry researchers, and industry organizations. EPA will assess these new studies along with the Howard study as a part of our routine review of new information and data for potential incorporation in the GHG Inventory.

## **Enesta Jones**

U.S. EPA, Office of Media Relations

Desk: 202.564.7873

Cell: 202.236.2426

Catherine C. Milbourn

U.S. EPA HQ

Office of the Administrator

Office of Media Relations

202-564-7849 (office)

202-420-8648 (mobile)

Milbourn.cathy@epa.gov

ED\_001785D\_00003686-00008

To:

McKittrick, Alexis MW[amckittr@ida.org]

From: Sent: Subject:	Weitz, Melissa Mon 6/13/2016 7:47:13 PM RE: Touche Howard in Washington Post		
Hi Alexis	5,		
Yes, I saw it			
I was out	of the office last Thursday and Friday. I'll give you a call tomorrow.		
Melissa			
Sent: Fri To: Weit Cc: DeFi	IcKittrick, Alexis MW [mailto:amckittr@ida.org] day, June 10, 2016 2:05 PM z, Melissa <weitz.melissa@epa.gov> gueiredo, Mark <defigueiredo.mark@epa.gov> Touche Howard in Washington Post</defigueiredo.mark@epa.gov></weitz.melissa@epa.gov>		
Melissa,			
https://w	ou haven't already seen this (but I'm guessing you have): www.washingtonpost.com/news/energy-environment/wp/2016/06/09/this-heated-fight- hane-emissions-is-almost-as-hot-as-the-gas/		
I left you	a voicemail on this topic. Give me a call when you get a chance.		
Best,			
Alexis			

ED\_001785D\_00004021-00001

Alexis McKittrick, Ph.D.

Research Staff Member

Institute for Defense Analyses

Science and Technology Policy Institute

1899 Pennsylvania Ave. NW, Suite 520

Washington, DC 20006

(202) 419-5412

amckittr@ida.org

To: McKittrick, Alexis[McKittrick.Alexis@epa.gov]

From: Weitz, Melissa

**Sent:** Fri 2/5/2016 6:40:22 PM **Subject:** Re: Need you ASAP in 4228A

On Suzie k's now. Calling Molly

Sent from my iPhone

On Feb 5, 2016, at 1:39 PM, McKittrick, Alexis < McKittrick. Alexis@epa.gov > wrote:

Touche Howard invited press reporters to 1:30PM call. Can we proceed? If so, anything special we need to say?

Alexis McKittrick, Ph.D.

Climate Change Division

U.S. Environmental Protection Agency

Phone: 202-343-9153

E-mail: mckittrick.alexis@epa.gov

To: McKittrick, Alexis[McKittrick.Alexis@epa.gov]

From: Weitz, Melissa

**Sent:** Mon 1/25/2016 5:05:22 PM **Subject:** Re: tomorrow's meeting

It's canceled. Trying to figure out how to cancel the invite from my phone.

Sent from my iPhone

On Jan 25, 2016, at 11:54 AM, McKittrick, Alexis < McKittrick. Alexis@epa.gov > wrote:

Hi Melissa,

Any read of if the Touche Howard meeting for tomorrow will be postponed? I am guessing he needs to travel up today for it, and the roads are still terrible. I am hoping to telework tomorrow, but I would try to come in if this meeting is still on. I think the more EPA folks in the room the better.

Let me know when you can. Thanks!

Alexis

Alexis McKittrick, Ph.D.

Climate Change Division

U.S. Environmental Protection Agency

Phone: 202-343-9153

E-mail: mckittrick.alexis@epa.gov

From: Weitz, Melissa

**Location:** DCRoomWJCS4228AOAP/DC-OAR-OAP **Importance:** Normal

Subject: meeting on Hi-Flo Sampler with Touche Howard

**Start Date/Time:** Fri 2/5/2016 6:30:00 PM End Date/Time: Fri 2/5/2016 7:30:00 PM

Call in Ex. 6 - Personal Privacy Code Ex. 6 - Personal Privacy

A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

Weitz, Melissa From:

DCRoomWJCS4228AOAP/DC-OAR-OAP Location:

Importance: Normal

Subject: hold for meeting on Hi-Flo Sampler with Touche Howard Start Date/Time: Tue 1/26/2016 4:00:00 PM **End Date/Time:** Tue 1/26/2016 5:00:00 PM

Call in Ex. 6 - Personal Privacy ; code Ex. 6 - Personal Privacy

A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

To: Vincent, Marc[Vincent.Marc@epa.gov]

Cc: Banks, Julius[Banks.Julius@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]

From: DeFigueiredo, Mark
Sent: Tue 9/19/2017 8:03:07 PM

Subject: OIG Methane Assignment - Responses to Information Requests

Information Requests.docx Information Requests.zip

Hi Marc,

Attached are responses to the requests for information from OIG regarding their methane evaluation. I am also attaching a zipped folder that contains copies of emails and presentations that were requested by OIG; the file size of the zipped folder is about 29 megabytes. Let us know if you have any questions.

We would appreciate it if you would send these along to OIG.

Thanks,

Mark

To: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]

From: Weitz, Melissa

Sent: Wed 12/9/2015 10:26:08 PM Subject: FW: Draft Email to Dave

Howard Energy Science and Engineering Analysis of UT Data Set 2015.pdf ES&T Comment on Allen et al. Methane Emissions from Process Equipment.pdf

Dave Allen Response to ES&T Letter.pdf

Touche Response to Dave Allen Comment in ESE Submitted 09 10 2015.pdf

. . .

From: Touche Howard [mailto:touche.howard@indacoags.com]

Sent: Wednesday, December 09, 2015 5:25 PM

To: allen@che.utexas.edu; McKittrick, Alexis; terri\_shires@aecom.com; matt.harrison@aecom.com; Weitz, Melissa; Gunning, Paul; McCabe, Janet Cc: RAlvarez@edf.org; shamburg@edf.org; Fernandez, Roger; rharriss@edf.org; matt.harrison@urs.com; ritterk@api.org; dnelson@edf.org; sedlak-office@est.acs.org; dmccabe@catf.us; dlyon@edf.org; dave.maxwell@urs.com; dschroeder@catf.us; dzavala@edf.org; Chuck Kolb; Gamas, Julia; linda.lee@arb.ca.gov; bmordick@nrdc.org; amrowka@arb.ca.gov; adam.pacsi@chevon.com; casey.pickering@erg.com; Wisetiawa@arb.ca.gov; Smith, James-D; Snyder, Jennifer; paige.sprague@tceq.texas.com; michael.ege@tceq.texas.gov

Subject: Draft Email to Dave

#### Dave --

Now that the EPA is considering using your initial EDF study at production sites (published in PNAS in 2013) and your follow-up study on pneumatic controllers (published in ES&T in 2014), it's critical that we resolve the Hi-Flow sensor failure and other quality assurance issues surrounding those studies as soon as possible. The quickest way to do that is for us to directly discuss these issues with EPA, and I think once you understand the evidence, you'll be able to see the problems immediately. To that end, let's try to get together tomorrow or Friday. (Melissa and Alexis - I can come up and meet with you either day, and if Dave can't make it, he can call in.)

My biggest concern is safety -- having an instrument that reports natural gas leaks far lower than they actually are is clearly a huge safety issue, and as long as you tell people that this problem didn't occur in your work, it will be very hard for anyone to take it seriously. Meanwhile, for you and EPA, this also represents important health and environmental concerns. And of course since you were chair of the EPA Science Advisory Board while you were conducting this research, and the Hi-Flow sampler is one of the methods approved by EPA to make measurements for their greenhouse gas reporting program under Subpart W, I'm sure you feel a special responsibility to address these issues as soon as possible.

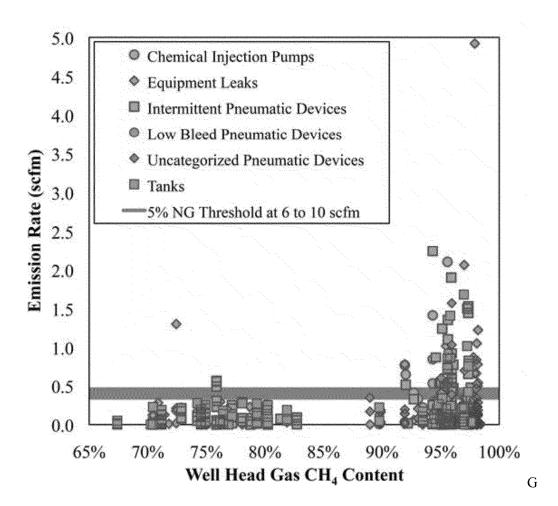
I've attached my ESE paper outlining the problems in your initial 2013 production study as well as my letter and your response about the 2014 study. I've also attached a reply that I wrote in response to your commentary on my paper in ESE, because even though you withdrew that commentary after seeing my response, I think my response did clarify some of the issues.

Since we unfortunately haven't had an opportunity to discuss these issues directly, I'll summarize

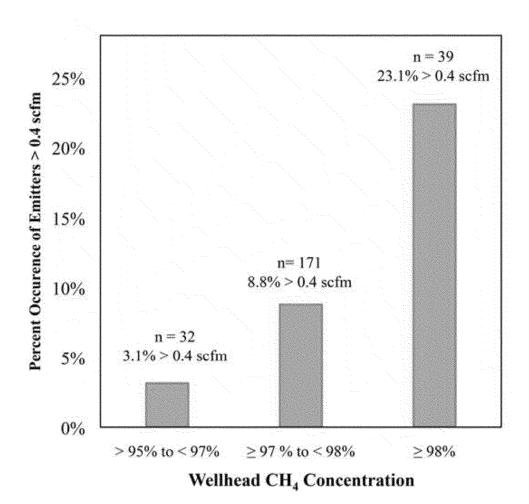
the evidence here and what I believe are your counterpoints, based on your reviews of my paper and the commentary you submitted. I also want to allay your concerns, which you've stated to others, that I'm raising these issues because I want to sell my own samplers or services. I'm only wrapping up loose ends now, and after this I won't be working in this area any more.

The first issue is sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS), where it can fail to transition from the low range (0 to 5% gas) catalytic oxidation sensor to the high range (5 to 100% gas) thermal conductivity detector, which can cause the sampler to report large leaks as being much smaller that they are. We don't know why this happens, but there's no question that it can, because we demonstrated it in three different instruments, including yours. It doesn't seem to occur for pure methane streams, but we've seen it in the field for gas streams with methane content as high as 91% (J. Air Waste Manag. Assoc. 65:856–862. doi: 10.1080/10962247.2015.1025925).

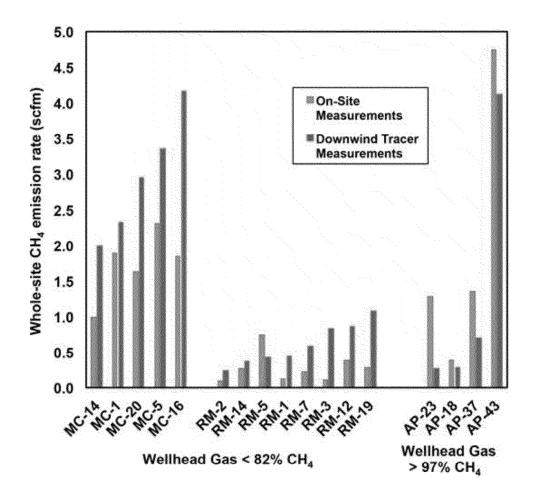
The effect of this problem is clear in your Phase I data, which I've plotted below showing emission rate as a function of site methane composition. As you can see, most of the high emitters only show up at sites with high methane compositions, and there's no reason that should happen in the real world, especially when you consider that it occurs for several different types of sources.



Now I believe your counter argument is that this phenomenon is due to air pollution control regulations reducing emissions in the Rocky Mountain region, where the methane content of the gas is lower as well. However, several things tell us that's not the cause of the trend in the figure above. First, even when you take the Rocky Mountain region out of the analysis, there's still far more high emitters at sites with higher methane content. Second, even within just the Appalachia region, the occurrence of high emitters increases dramatically over a very narrow range of site methane compositions, from 95% to 98% methane (shown below). What that tells us is that sampler can start seeing some of the high emitters once methane composition is in the range of 95%, but is still missing a lot of them until methane composition gets up to the 97 to 98% range. This is also an extremely important indicator that this problem could be occurring even for gas streams with methane content above 95%, meaning the problem could occur in all segments of the natural gas industry.



Finally, your emissions measurements made by tracer technique confirm that sensor failure occurred and that the trend of emission rate vs concentration is not caused by regional differences. Now, in your comment you said you found my analysis of your tracer data complex, probably because I showed how Hi-Flow measurements got lower and lower than the tracer measurements for sites with fewer estimated emissions from sources like tanks. So I've simplified that analysis, and just removed the two sites that had 98% or more of the emissions estimated as opposed to measured. This comparison of the tracer versus on site Hi-Flow measurements is shown below.



So clearly, as you've suggested, there are regional differences, assuming these sites are representative. The tracer data shows that the emissions from sites in the Rocky Mountain (RM) region are lower than the sites in the Mid-continent (MC) region, although in the same range as 75% of the Appalachia (AP) sites. But just as clearly, the sites with lower methane content (Rocky Mountain and Mid-continent, where sensor failure might occur consistently) have far lower (about a factor of two) Hi-Flow measurements than the tracer technique. Meanwhile, the sites with high methane content (Appalachia, where the problem isn't expected to occur) have Hi-Flow measurements close to or exceeding the tracer measurements. Keep in mind that because some of the on-site data comes from estimates, this masks the magnitude of the error, but at least this is a simple comparison.

Now if the variations between the tracer and the Hi-Flow were due to random experimental errors, then we'd expect roughly 50% of the sites to have tracer greater than Hi-Flow, and 50% lower. It's actually a 70/30 split, but the remarkable thing is that we can predict which region will have tracer greater than Hi-Flow and which won't. This is pretty much the same thing as me being able to walk into a bar and betting the barmaid that if I stand on her side of the bar and flip a coin it will always come up heads, but if I stand on my side of the bar and flip a coin, it will

always come up tails. And in between drinks, we run that experiment, and it turns out that I'm right 16 out of 17 times.

Now that's a bar bet I'd like to be able to make routinely.

You also said in your unpublished comment to ESE that the testing I conducted on your instrument and others in March of 2013 showed a low occurrence of this problem. That's true of course, but I was surprised you said that, since you know that immediately after we did that testing that I met with some very experienced Hi-Flow technicians who specifically told me that they had fixed some of their samplers that had been reporting leaks too low by upgrading the sampler's software. Since all of the samplers we tested when we tested yours had new generation software, the only real surprise is that we saw any failure at all, and that failure was in your sampler. So even though new software improves the problem, it doesn't fix it completely. Additionally, there are lots of these samplers around the US and the world using older software, and lots of data that has been collected using samplers prior to software upgrades.

One other argument you made was that your Phase I pneumatic data, made by Hi-Flow, was higher than your Phase II pneumatic data, collected by meter, and if your Hi-Flow had been reporting too low, this should have been the other way around. The reason this isn't true is that your Phase I pneumatic data is clearly an emitter data set (95% of them are emitting) while your Phase II data set is a comprehensive data set (about 21% are actual emitters). So you accidentally excluded sampling zero emitters in Phase I, which biases that data high by a factor of four to five, and offsets any Hi-Flow sensor failure. Additionally, the Phase II data actually shows exactly what I predicted to you it would show -- that the high emitters are more predominant at sites with lower methane compositions when measured by the inline meter as opposed to your Phase I measurements, where the sensor failure caused the high emitters at those sites to be under reported.

In any case, I think this shows that it probably would have been better to involve me directly in discussions you had with the EDF committees and others about this problem after I brought it to you in October of 2013, because I could have explained immediately why the reasons you thought this problem didn't affect your Phase I data were incorrect. It has been puzzling to me that given the overwhelming evidence, that this problem wasn't obvious to you, but I'm wondering if that might be due to inexperience with field measurements. As an example, in both your Phase I and Phase II papers, you incorrectly describe the operation of the Hi-Flow sensors, and without understanding that the Hi-Flow has to to switch back and forth between sensors to make accurate measurements, it's probably impossible for you to understand the sensor transition problem.

I'm wondering if inexperience might have also led to the problems in your Phase II work as well. It's a harsh environment for meters to be transported between field sites on rough roads and have raw natural gas run through them, and I think most people with experience in field measurements would have built in a routine testing of those meters during the project, rather than just check them before and after the project as you did. When you're out in the field looking at pneumatics, you see lots of them with oil or other hydrocarbon accumulations, so it's easy to picture how the meter sensor could get fouled, as yours did. I would think at least a weekly multi-point meter

calibration and a daily single point flow check would be required to ensure accurate measurements. which is what was done during the EDF WSU distribution work. The Indaco Hi-Flows that were used in that project have a very similar flow measurement system to your Fox meter, which is a thermal element in a tube, and even though the distribution study was a much less harsh environment, where leaks of relatively clean distribution gas were measured and the flow system dilutes those leaks with air before the gas hits the sensors, full scale weekly calibrations and single point daily flow checks were conducted.

Now, as you remember, while that project was ongoing, I found that one of your two primary meters was measuring too low by a factor of three. Well, that's not a surprise, given the harsh environment. I haven't used the particular meter that you were using before, but I did look at the manual for it, and it clearly states that a dirty sensor will cause measurements to be too low.

But I think how you addressed that issue indicates further inexperience. Since you don't mention the meter test I made showing it was a factor of three too low in your paper, but only indicate that you found the problem post project, it appears that you just kept using the meter, without trying to figure out what was wrong with it, and without instituting any additional meter checks.

Instead, it wasn't until the end of the project that you did any further checks, and at that point the response of the meter had changed again, to being low by about 34%. In order to understand more about the problem, you tried to use your Hi-Flow data to validate the meter results. Now your laboratory comparisons of the two for the most part are excellent and agree within 10%. But surprisingly, your field comparisons of the Hi-Flow to the meters are far worse. For measurements where either one or the other was >0.5 scfh, only 4 out of 19 (21%) are within 25%, and even for measurements >6 scfh, only 3 out of 10 (30%) are within 25% of each other. You do allude to the possibility of leaks affecting the measurements but don't give any indication that you tried to quantify the leaks that you think affected the measurements.

For comparison, in the WSU distribution work, where direct and tracer measurements were compared, 10 out of 14 (71%) were within 50% of each other, over a range of about 0.6 to 56 scfh. Now I would have liked that to be better, but I think I understand some of the challenges, one being that some of those that are far off are at really low emission rates, so missing just one source could throw you off a lot. But keep in mind, that's measuring the whole M&R facility or an underground leak, and comparing it to a downwind tracer flux measurement, so you have lots of challenges including multiple measurements at the facility and tracer source configurations.

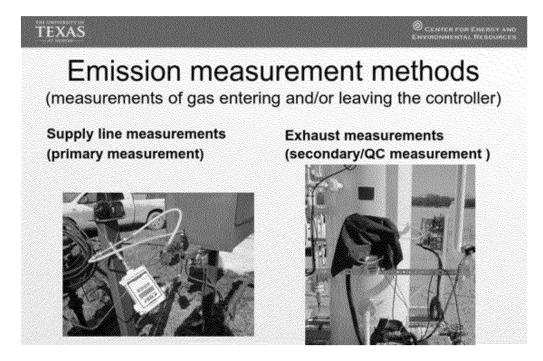
But for your pneumatic work, while doing a direct comparison of Hi-Flow to meters, for just single sources, only 7 of 19 (37%) were within 50% of each other over a similar emission range of 0.5 to 60 scfh.

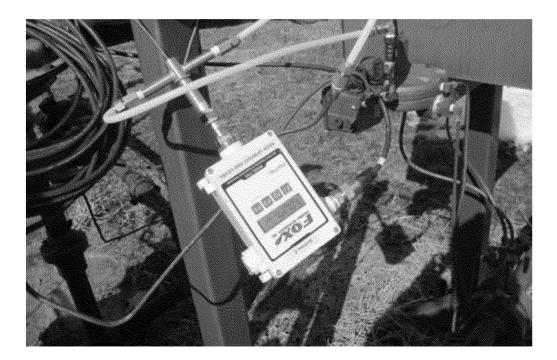
So unfortunately your comparison of High Flow to meters should not have been used to justify correcting your meter, especially when my direct test of that meter's performance mid-project showed it was much worse than the post project check indicated.

Another indication of the meter uncertainty came from Matt Harrison, who was present when I found that your meter was reading a factor of three too low, and said at the time, "Yeah,

everyone knows that meter is flaky. You can hook it up to an pneumatic and hear the pneumatic fire but not see anything on the meter."

Now, along with the sensor getting dirty, your meter measurements might have been affected by two other factors mentioned in the meter manual. These meters are supposed to be oriented upright, and you need a certain length of straight run (I think for the meter you were using, six inches) before the meter. However, it appears, looking at a slide from the presentation about the project on your website shown below, that those conditions weren't met either. Although you can see in the close up that the meter is marked with a label that says "Keep Upright and Level", that condition hasn't been met in either configuration pictured. Additionally, the entrance length doesn't appear to meet the required distance either.





I think these issues were all compounded by perhaps your lack of experience with what information editors and reviewers need to evaluate field measurement papers. Your meter problem is only mentioned in a footnote on page 59 of your Supplementary Information, and was likely missed by the editor and reviewers. But if reviewers with substantial field experience understood the entire picture -- that you only checked your calibration before and after the project, that there was an undisclosed mid project test showing meter performance was much worse than the correction you applied, that after you were shown one meter was faulty in the middle of the project that you simply continued to use it without finding out what was wrong or instituting improved calibration checks, "that everyone knew that meter was flaky," and that your Hi-Flow and meter field measurements don't compare very well -- I believe they would conclude that you didn't meet the fundamentals of quality assurance and that the paper would have been rejected.

So unfortunately neither the Phase I or Phase II data should be used by EPA. Although there may be large uncertainties in inventories, we shouldn't include numbers that have such large question marks. Think about cancer treatments. Those have very uncertain outcomes, but that doesn't mean that we don't want good quality assurance in cancer research or in the dosages of drugs or radiation therapy that are used. And when you consider the broad environmental impact of air toxics to the communities surrounding oil and gas facilities as well as the consequences of climate change, it's critical that we use the best data possible.

And as I said at the start, safety is my biggest concern regarding the HiFlow sensor failure, and I think perhaps again inexperience has caused you not to fully appreciate what a critical safety issue this is. I've spent a lot of time measuring leak rates at natural gas facilities, and I've seen

facility personnel shut down units in order to address large leaks that we found due to safety concerns -- I've done lots of leak measurement programs that were focused more on the integrity of the facility rather than the issue of greenhouse gases. Additionally, we don't know how the sampler might be used in the future -- for instance, given GTI's and WSU's work in distribution, it might be used to rank leaks for repair in that segment (even though the WSU study used a different version of the sampler not affected by this problem).

James Reason wrote a really great book about the Swiss cheese theory of disasters (*Reason, James (1997). Managing the risks of organizational accidents. Aldershot: Ashgate. <u>ISBN 1840141042</u>.) which is widely studied in aviation, engineering, and the fire service. In it he describes how the really terrible things that happen usually occur because there have been failures on several levels, and those failures line up to let something really bad happen.* 

We had a terrible example of that happen here in North Carolina a couple of years ago. A couple checked into a hotel, and the next morning they were dead. Seven weeks later, an 11 year old boy died in the same room, and although his mother survived, she had permanent brain damage.

All of that could have been avoided, because they were killed by carbon monoxide. You might have seen this on 20/20:

 $\underline{http://abcnews.go.com/US/north-carolina-best-western-room-225-open-deaths/story?id=21564280}$ 

Here's how it all lined up:

- 1) The hotel pulled an old pool heater out of another property and installed it at that hotel, even though it was at the end of its life, meaning it was inefficient and was at risk for producing more carbon monoxide, and they didn't get a city inspection permit;
- 2) The vent pipe was corroded, and let the CO escape under the room where everyone was killed;
- 3) There were holes in the fire place in the room that let more CO in that would have come in otherwise;
- 4) The CO detectors that were supposed to have been installed in the rooms were actually natural gas detectors, installed by mistake.

So that's what killed the first couple.

But here's why the little boy died:

- 1) Three days after the couple was killed, a family in the room above got really sick, and complained, but the hotel didn't pay attention;
- 2) The family of the first couple raised warnings with the hotel and police that it might be CO

and again no one paid attention;

- 3) The medical examiner didn't visit the scene of the first couple and see that the wife had thrown up (an important clue in CO poisoning)
- 4) He also didn't put an expedite order on their blood work, so it sat for 40 days (two people simultaneously dead in an enclosed space -- a huge alarm bell for some toxic substance, especially CO);
- 5) He finally got the results four days before the child died in the room, but;
- 6) He sat on them for a week and by the time he finally sent them out to the local police; the child was had been killed and his mother permanently injured.

That's a tragic story, all right. And as you can imagine, the two families are suing everyone in sight that had anything to do with any of that, and I would too if I had lost a family member. Meanwhile, the DA also charged the head of the hotel management group with three counts of manslaughter, and all of those cases are still on going.

That's just one example of how tragic things can happen when we don't do everything possible to ensure people's safety. But if you do just a little bit of research, you'll see how frighteningly common that is.

So I know you'll want to address the Hi-Flow sensor failure issue immediately.

As I suggested at the start, let's do it this week. I can go up and meet with EPA tomorrow or Friday, and if you can't be there in person, you can call in, and you can have any interested parties from EDF or your production committees call in as well. i know everyone's busy, but this won't take more than an hour, and I think we should all be willing to make that much time for such a critical issue.

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lust let	me know	when	the	hest time	- tor	all of	VOIL 19

Thanks,

Touche'

To: Irving, Bill[Irving.Bill@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; McKittrick,

Alexis[McKittrick.Alexis@epa.gov]; Thoma, Eben[Thoma.Eben@epa.gov]

From: Weitz, Melissa

**Sent:** Fri 2/12/2016 8:12:24 PM

Subject: FW: Meeting on Hi-Flo Sampler with Touché Howard

# Ex. 5 - Deliberative Process

From: Harrison, Matt [mailto:matt.harrison@aecom.com]

Sent: Thursday, February 11, 2016 3:49 PM

To: McKittrick, Alexis; Weitz, Melissa

Cc: Shires, Terri; Thoma, Eben; DeFigueiredo, Mark Subject: Meeting on Hi-Flo Sampler with Touché Howard

Dear Alexis and Melissa.

I heard the web presentation made by Mr. Touche Howard when he visited EPA last Friday 2/5/16. Mr. Howard invited me to attend. Thank you for allowing me to listen in. I was surprised by the presence of press at the meeting.

If EPA would like a technical response from the UT-EDF authors to his theories and criticisms, I believe the PI and myself would be happy to discuss that with EPA. Alternately, we can send you some written comments, if you prefer.

Bottom line, while Mr. Howard has some good observations, he has not characterized all the facts appropriately.

If you need an official response, we would like to have the slide deck he presented and shared at your web meeting. Alexis, as your note to Terri Shires suggested, I have requested a copy of the slides from Mr. Howard, but have not received any response to that request.

Let me know if you care to discuss this further.

Thank you,						
Matt						
Matthew Harrison, P.E.						
Vice President						

Americas - Upstream Oil & Gas

## matt.harrison@AECOM.com

512-694-0572

# **AECOM**

9400 Amberglen Blvd., Austin, Texas 78729

#### www.aecom.com

From: McKittrick, Alexis [mailto:McKittrick.Alexis@epa.gov]

Sent: Tuesday, February 09, 2016 2:12 PM

To: Shires, Terri Cc: Harrison, Matt

Subject: RE: meeting on Hi-Flo Sampler with Touché Howard

Terri,

Attendees of this meeting who are not affiliated with the EPA should contact Touche Howard directly for copies of the slides.

Thanks,

Alexis

From: Shires, Terri [mailto:terri.shires@aecom.com]

Sent: Tuesday, February 09, 2016 9:26 AM

**To:** McKittrick, Alexis < McKittrick.Alexis@epa.gov > Cc: Harrison, Matt < matt.harrison@aecom.com >

Subject: RE: meeting on Hi-Flo Sampler with Touché Howard

Alexis,

Could you please distribute the slides that Touché' presented last week?

Thank you,

#### Terri Shires

Senior Engineer and Project Manager, Design and Construction Services, Gulf Coast Region D +1-512-419-5466 M +1-512-497-6482 Terri.Shires@aecom.com

#### **AECOM**

9400 Amberglen Blvd. Austin, Texas 78729, USA T +1-512-454-4797 aecom.com

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From: McKittrick, Alexis [mailto:McKittrick.Alexis@epa.gov]

Sent: Friday, February 05, 2016 12:56 PM

To: ralvarez@edf.org; lisa.song@insideclimatenews.org; nancy@ncwarn.org; Shires, Terri

Subject: Fwd: meeting on Hi-Flo Sampler with Touche Howard

## Sent from my iPhone

https://epawebconferencing.acms.com/r2fk2tdpn9x/

From: Weitz, Melissa

Sent: Wednesday, December 23, 2015 4:35 PM

To: Weitz, Melissa; DeFigueiredo, Mark; Waltzer, Suzanne; McKittrick, Alexis;

Macpherson, Alex; Moore, Bruce; Thoma, Eben; Thompson, Lisa; Hambrick, Amy; Banks,

Julius; Irving, Bill **Cc:** Howard, Jodi

Subject: meeting on Hi-Flo Sampler with Touche Howard

When: Friday, February 5, 2016 1:30 PM-2:30 PM. Where: DCRoomWJCS4228AOAP/DC-OAR-OAP

Call in 866-299-3188; code 2023439897.

A hold for now. We probably don't need everyone to attend/call in. We'll sort it out as we get closer to the date.

To: Irving, Bill[Irving.Bill@epa.gov]

From: Weitz, Melissa

**Sent:** Mon 12/14/2015 10:30:12 PM

**Subject:** FW: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

,,,,

A preview for tomorrow.

From: Touche Howard [mailto:touche.howard@indacoaqs.com]

Sent: Monday, December 14, 2015 4:42 PM

To: allen@che.utexas.edu

Cc: McKittrick, Alexis < McKittrick.Alexis@epa.gov>; terri shires@aecom.com; Weitz, Melissa < Weitz.Melissa@epa.gov>; Gunning, Paul < Gunning.Paul@epa.gov>; McCabe, Janet < McCabe.Janet@epa.gov>; RAlvarez@edf.org; shamburg@edf.org; Fernandez, Roger < Fernandez.Roger@epa.gov>; rharriss@edf.org; ritterk@api.org; dnelson@edf.org; sedlak-office@est.acs.org; dmccabe@catf.us; dlyon@edf.org; Maxwell, Dave (Austin) < dave.maxwell@aecom.com>; dschroeder@catf.us; dzavala@edf.org; Chuck Kolb < kolb@aerodyne.com>; Gamas, Julia < Gamas.Julia@epa.gov>; linda.lee@arb.ca.gov; bmordick@nrdc.org; amrowka@arb.ca.gov; casey.pickering@erg.com; Wisetiawa@arb.ca.gov; Smith, James-D < Smith.James-D@epa.gov>; Snyder, Jennifer < Snyder.Jennifer@epa.gov>; michael.ege@tceq.texas.gov; paige.sprague@tceq.texas.gov; adam.pacsi@chevron.com; Jeff.Rees@pxd.com; matt.harrison@aecom.com; alr@andrew.cmu.edu; awilcox@harcresearch.org; andres.restrepo@sierraclub.org; gabrielle.petron@noaa.gov; natalie.spiegel@sierraclub.org; nathan.matthews@sierraclub.org; rsawyer@me.berkeley.edu; Ganapathy, Roopa (EC/EC) < Roopa.Ganapathy@canada.ca>; ygowrishankar@nrdc.org; dan.hill@pe.tamu.edu; Matthew.Fraser@asu.edu; seinfeld@caltech.edu

Subject: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

Dave --

I think that Matt's statement of "I see no safety issue" (regarding the Bacharach Hi-Flow sampler's problem of reporting leaks as far smaler than they actually are) might have resulted from your team either not being aware of all the potential uses of the Hi-Flow sampler or from having a somewhat narrow view of what problems can compromise safety.

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Did we prevent explosions in those cases? We'll never know, but we did provide one layer of defense by eliminating imminently dangerous conditions. So if only 1% of facilities have a dangerous underlying condition that might go undiscovered if a Hi-Flow sampler fails, is it really worth an hour of your time to address this issue? I think most people would say yes.

Even high flow surveys that focus on research or greenhouse gas reporting have the opportunity to reduce dangerous conditions if done properly. I think the protocol in most (hopefully all) leak measurement programs, whatever their focus, is to immediately alert facility operators of any hazardous conditions found. So it's certainly not acceptable to leave hazards unidentified due to sampler failure just because many surveys are focused on greenhouse gas emissions instead of facility integrity.

Other instances where sampler failure might affect safety are when it is used to make an on the spot repair decision when a leak is discovered by an operator and when it is used to survey facilities being put into initial service. And as I pointed out previously, we don't know all the ways a sampler might be used now or in the future. If, for instance, it were used to rank distribution leaks for repair, under reporting large leaks could have tragic consequences.

Now you might think that other indications, such as an IR camera, or auditory, visual, and olfactory (AVO) detection would provide clues that a leak was much larger than the sampler indicated, but most people just don't have that level of experience, and a noisy and/or hot environment can make it even more difficult. There's an excellent example of this in your Phase II pneumatic work, where Device No. XQ01-PC04 was measured both by Hi-Flow (0.13 scfh) and meter (37.37 scfh), and you assume the Hi-Flow measurement is too low due to the device not being adequately enclosed. However, this device was a continuous bleed controller with a high emission rate (in the top 20% of the continuous controllers you measured). Consequently, even though the Hi-Flow was making an easy to read steady state measurement for most of that interval, your technicians did not recognize that the Hi-Flow reading was almost 300 times too low (if they had, they would have certainly attempted to correct the problem while the measurement was being made). This highlights that even people who had been making these type of measurements day after day during an extensive field program could not accurately judge emission rates without reliable instrumentation.

And although safety systems like gas detectors or hot work permits provide one line of defense, they can't always protect the facility from a leak that could have been fixed but wasn't, and then either failed catastrophically or found an ignition source before automatic detection shut down equipment. Having been to so many facilities, I've heard lots of stories of past explosions. My favorite was was told to me by an operator who was the son of a compressor station manager. When he was growing up, they lived near the station, and one night after dinner he wanted to go to the mechanic's shop at the site to work on his car. Oh, no, his mother says, it's your turn to do the dishes. So there he is, sulking at the sink, when the station blows up, basically right in front of him as he's watching out the kitchen window, and destroying with it the mechanic's shop where he would have been if his mother hadn't made him wash dishes.

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Matt Harrison

512-694-0572

Sent from my iPhone

On Dec 9, 2015, at 2:25 PM, "Touche Howard" < touche.howard@indacoaqs.com > wrote:

Dave --

Now that the EPA is considering using your initial EDF study at production sites (published in PNAS in 2013) and your follow-up study on pneumatic controllers (published in ES&T in 2014), it's critical that we resolve the Hi-Flow sensor failure and other quality assurance issues surrounding those studies as soon as possible. The quickest way to do that is for us to directly discuss these issues with EPA, and I think once you understand the evidence, you'll be able to see the problems immediately. To that end, let's try to get together tomorrow or Friday. (Melissa and Alexis - I can come up and meet with you either day, and if Dave can't make it, he can call in.)

My biggest concern is safety -- having an instrument that reports natural gas leaks far lower than they actually are is clearly a huge safety issue, and as long as you tell people that this problem didn't occur in your work, it will be very hard for anyone to take it seriously. Meanwhile, for you and EPA, this also represents important health and environmental concerns. And of course since you were chair of the EPA Science Advisory Board while you were conducting this research, and the Hi-Flow sampler is one of the methods approved by EPA to make measurements for their greenhouse gas reporting program under Subpart W, I'm sure you feel a special responsibility to address these issues as soon as possible.

I've attached my ESE paper outlining the problems in your initial 2013 production study as well as my letter and your response about the 2014 study. I've also attached a reply that I wrote in response to your commentary on my paper in ESE, because even though you withdrew that commentary after seeing my response, I think my response did clarify some of the issues.

Since we unfortunately haven't had an opportunity to discuss these issues directly, I'll summarize the evidence here and what I believe are your counterpoints, based on your reviews of my paper and the commentary you submitted. I also want to allay your concerns, which you've stated to others, that I'm raising these issues because I want to sell my own samplers or services. I'm only wrapping up loose ends now, and after this

I won't be working in this area any more.

The first issue is sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS), where it can fail to transition from the low range (0 to 5% gas) catalytic oxidation sensor to the high range (5 to 100% gas) thermal conductivity detector, which can cause the sampler to report large leaks as being much smaller that they are. We don't know why this happens, but there's no question that it can, because we demonstrated it in three different instruments, including yours. It doesn't seem to occur for pure methane streams, but we've seen it in the field for gas streams with methane content as high as 91% (J. Air Waste Manag. Assoc. 65:856–862. doi: 10.1080/10962247.2015.1025925).

The effect of this problem is clear in your Phase I data, which I've plotted below showing emission rate as a function of site methane composition. As you can see, most of the high emitters only show up at sites with high methane compositions, and there's no reason that should happen in the real world, especially when you consider that it occurs for several different types of sources.

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Now I believe your counter argument is that this phenomenon is due to air pollution control regulations reducing emissions in the Rocky Mountain region, where the methane content of the gas is lower as well. However, several things tell us that's not the cause of the trend in the figure above. First, even when you take the Rocky Mountain region out of the analysis, there's still far more high emitters at sites with higher methane content. Second, even within just the Appalachia region, the occurrence of high emitters increases dramatically over a very narrow range of site methane compositions, from 95% to 98% methane (shown below). What that tells us is that sampler can start seeing some of the high emitters once methane composition is in the range of 95%, but is still missing a lot of them until methane composition gets up to the 97 to 98% range. This is also an extremely important indicator that this problem could be occurring even for gas streams with methane content above 95%, meaning the problem could occur in all segments of the natural gas industry.

Finally, your emissions measurements made by tracer technique confirm that sensor failure occurred and that the trend of emission rate vs concentration is not caused by regional differences. Now, in your comment you said you found my analysis of your tracer data complex, probably because I showed how Hi-Flow measurements got lower and lower than the tracer measurements for sites with fewer estimated emissions from sources like tanks. So I've simplified that analysis, and just removed the two sites that had 98% or more of the emissions estimated as opposed to measured. This comparison

of the tracer versus on site Hi-Flow measurements is shown below.

So clearly, as you've suggested, there are regional differences, assuming these sites are representative. The tracer data shows that the emissions from sites in the Rocky Mountain (RM) region are lower than the sites in the Mid-continent (MC) region, although in the same range as 75% of the Appalachia (AP) sites. But just as clearly, the sites with lower methane content (Rocky Mountain and Mid-continent, where sensor failure might occur consistently) have far lower (about a factor of two) Hi-Flow measurements than the tracer technique. Meanwhile, the sites with high methane content (Appalachia, where the problem isn't expected to occur) have Hi-Flow measurements close to or exceeding the tracer measurements. Keep in mind that because some of the on-site data comes from estimates, this masks the magnitude of the error, but at least this is a simple comparison.

Now if the variations between the tracer and the Hi-Flow were due to random experimental errors, then we'd expect roughly 50% of the sites to have tracer greater than Hi-Flow, and 50% lower. It's actually a 70/30 split, but the remarkable thing is that we can predict which region will have tracer greater than Hi-Flow and which won't. This is pretty much the same thing as me being able to walk into a bar and betting the barmaid that if I stand on her side of the bar and flip a coin it will always come up heads, but if I stand on my side of the bar and flip a coin, it will always come up tails. And in between drinks, we run that experiment, and it turns out that I'm right 16 out of 17 times.

Now that's a bar bet I'd like to be able to make routinely.

You also said in your unpublished comment to ESE that the testing I conducted on your instrument and others in March of 2013 showed a low occurrence of this problem. That's true of course, but I was surprised you said that, since you know that immediately after we did that testing that I met with some very experienced Hi-Flow technicians who specifically told me that they had fixed some of their samplers that had been reporting leaks too low by upgrading the sampler's software. Since all of the samplers we tested when we tested yours had new generation software, the only real surprise is that we saw any failure at all, and that failure was in your sampler. So even though new software improves the problem, it doesn't fix it completely. Additionally, there are lots of these samplers around the US and the world using older software, and lots of data that has been collected using samplers prior to software upgrades.

One other argument you made was that your Phase I pneumatic data, made by Hi-Flow, was higher than your Phase II pneumatic data, collected by meter, and if your Hi-Flow had been reporting too low, this should have been the other way around. The reason this isn't true is that your Phase I pneumatic data is clearly an emitter data set (95% of them are emitting) while your Phase II data set is a comprehensive data set

(about 21% are actual emitters). So you accidentally excluded sampling zero emitters in Phase I, which biases that data high by a factor of four to five, and offsets any Hi-Flow sensor failure. Additionally, the Phase II data actually shows exactly what I predicted to you it would show -- that the high emitters are more predominant at sites with lower methane compositions when measured by the inline meter as opposed to your Phase I measurements, where the sensor failure caused the high emitters at those sites to be under reported.

In any case, I think this shows that it probably would have been better to involve me directly in discussions you had with the EDF committees and others about this problem after I brought it to you in October of 2013, because I could have explained immediately why the reasons you thought this problem didn't affect your Phase I data were incorrect. It has been puzzling to me that given the overwhelming evidence, that this problem wasn't obvious to you, but I'm wondering if that might be due to inexperience with field measurements. As an example, in both your Phase I and Phase II papers, you incorrectly describe the operation of the Hi-Flow sensors, and without understanding that the Hi-Flow has to to switch back and forth between sensors to make accurate measurements, it's probably impossible for you to understand the sensor transition problem.

I'm wondering if inexperience might have also led to the problems in your Phase II work as well. It's a harsh environment for meters to be transported between field sites on rough roads and have raw natural gas run through them, and I think most people with experience in field measurements would have built in a routine testing of those meters during the project, rather than just check them before and after the project as you did. When you're out in the field looking at pneumatics, you see lots of them with oil or other hydrocarbon accumulations, so it's easy to picture how the meter sensor could get fouled, as yours did. I would think at least a weekly multi-point meter calibration and a daily single point flow check would be required to ensure accurate measurements. which is what was done during the EDF WSU distribution work. The Indaco Hi-Flows that were used in that project have a very similar flow measurement system to your Fox meter, which is a thermal element in a tube, and even though the distribution study was a much less harsh environment, where leaks of relatively clean distribution gas were measured and the flow system dilutes those leaks with air before the gas hits the sensors, full scale weekly calibrations and single point daily flow checks were conducted.

Now, as you remember, while that project was ongoing, I found that one of your two primary meters was measuring too low by a factor of three. Well, that's not a surprise, given the harsh environment. I haven't used the particular meter that you were using before, but I did look at the manual for it, and it clearly states that a dirty sensor will cause measurements to be too low.

But I think how you addressed that issue indicates further inexperience. Since you don't mention the meter test I made showing it was a factor of three too low in your paper, but only indicate that you found the problem post project, it appears that you

just kept using the meter, without trying to figure out what was wrong with it, and without instituting any additional meter checks.

Instead, it wasn't until the end of the project that you did any further checks, and at that point the response of the meter had changed again, to being low by about 34%. In order to understand more about the problem, you tried to use your Hi-Flow data to validate the meter results. Now your laboratory comparisons of the two for the most part are excellent and agree within 10%. But surprisingly, your field comparisons of the Hi-Flow to the meters are far worse. For measurements where either one or the other was >0.5 scfh, only 4 out of 19 (21%) are within 25%, and even for measurements >6 scfh, only 3 out of 10 (30%) are within 25% of each other. You do allude to the possibility of leaks affecting the measurements but don't give any indication that you tried to quantify the leaks that you think affected the measurements.

For comparison, in the WSU distribution work, where direct and tracer measurements were compared, 10 out of 14 (71%) were within 50% of each other, over a range of about 0.6 to 56 scfh. Now I would have liked that to be better, but I think I understand some of the challenges, one being that some of those that are far off are at really low emission rates, so missing just one source could throw you off a lot. But keep in mind, that's measuring the whole M&R facility or an underground leak, and comparing it to a downwind tracer flux measurement, so you have lots of challenges including multiple measurements at the facility and tracer source configurations.

But for your pneumatic work, while doing a direct comparison of Hi-Flow to meters, for just single sources, only 7 of 19 (37%) were within 50% of each other over a similar emission range of 0.5 to 60 scfh.

So unfortunately your comparison of High Flow to meters should not have been used to justify correcting your meter, especially when my direct test of that meter's performance mid-project showed it was much worse than the post project check indicated.

Another indication of the meter uncertainty came from Matt Harrison, who was present when I found that your meter was reading a factor of three too low, and said at the time, "Yeah, everyone knows that meter is flaky. You can hook it up to an pneumatic and hear the pneumatic fire but not see anything on the meter."

Now, along with the sensor getting dirty, your meter measurements might have been affected by two other factors mentioned in the meter manual. These meters are supposed to be oriented upright, and you need a certain length of straight run (I think for the meter you were using, six inches) before the meter. However, it appears, looking at a slide from the presentation about the project on your website shown below, that those conditions weren't met either. Although you can see in the close up that the meter is marked with a label that says "Keep Upright and Level", that condition hasn't been met in either configuration pictured. Additionally, the entrance length doesn't appear to meet the required distance either.

I think these issues were all compounded by perhaps your lack of experience with what information editors and reviewers need to evaluate field measurement papers. Your meter problem is only mentioned in a footnote on page 59 of your Supplementary Information, and was likely missed by the editor and reviewers. But if reviewers with substantial field experience understood the entire picture -- that you only checked your calibration before and after the project, that there was an undisclosed mid project test showing meter performance was much worse than the correction you applied, that after you were shown one meter was faulty in the middle of the project that you simply continued to use it without finding out what was wrong or instituting improved calibration checks, "that everyone knew that meter was flaky," and that your Hi-Flow and meter field measurements don't compare very well -- I believe they would conclude that you didn't meet the fundamentals of quality assurance and that the paper would have been rejected.

So unfortunately neither the Phase I or Phase II data should be used by EPA. Although there may be large uncertainties in inventories, we shouldn't include numbers that have such large question marks. Think about cancer treatments. Those have very uncertain outcomes, but that doesn't mean that we don't want good quality assurance in cancer research or in the dosages of drugs or radiation therapy that are used. And when you consider the broad environmental impact of air toxics to the communities surrounding oil and gas facilities as well as the consequences of climate change, it's critical that we use the best data possible.

And as I said at the start, safety is my biggest concern regarding the HiFlow sensor failure, and I think perhaps again inexperience has caused you not to fully appreciate what a critical safety issue this is. I've spent a lot of time measuring leak rates at natural gas facilities, and I've seen facility personnel shut down units in order to address large leaks that we found due to safety concerns -- I've done lots of leak measurement programs that were focused more on the integrity of the facility rather than the issue of greenhouse gases. Additionally, we don't know how the sampler might be used in the future -- for instance, given GTI's and WSU's work in distribution, it might be used to rank leaks for repair in that segment (even though the WSU study used a different version of the sampler not affected by this problem).

James Reason wrote a really great book about the Swiss cheese theory of disasters (Reason, James (1997). Managing the risks of organizational accidents. Aldershot: Ashgate. ISBN 1840141042.) which is widely studied in aviation, engineering, and the fire service. In it he describes how the really terrible things that happen usually occur because there have been failures on several levels, and those failures line up to let something really bad happen.

We had a terrible example of that happen here in North Carolina a couple of years ago. A couple checked into a hotel, and the next morning they were dead. Seven weeks later, an 11 year old boy died in the same room, and although his mother survived, she had permanent brain damage.

All of that could have been avoided, because they were killed by carbon monoxide. You might have seen this on 20/20:

http://abcnews.go.com/US/north-carolina-best-western-room-225-open-deaths/story?id=21564280

Here's how it all lined up:

- 1) The hotel pulled an old pool heater out of another property and installed it at that hotel, even though it was at the end of its life, meaning it was inefficient and was at risk for producing more carbon monoxide, and they didn't get a city inspection permit;
- 2) The vent pipe was corroded, and let the CO escape under the room where everyone was killed;
- 3) There were holes in the fire place in the room that let more CO in that would have come in otherwise;
- 4) The CO detectors that were supposed to have been installed in the rooms were actually natural gas detectors, installed by mistake.

So that's what killed the first couple.

But here's why the little boy died:

- 1) Three days after the couple was killed, a family in the room above got really sick, and complained, but the hotel didn't pay attention;
- 2) The family of the first couple raised warnings with the hotel and police that it might be CO and again no one paid attention;
- 3) The medical examiner didn't visit the scene of the first couple and see that the wife had thrown up (an important clue in CO poisoning)
- 4) He also didn't put an expedite order on their blood work, so it sat for 40 days (two people simultaneously dead in an enclosed space -- a huge alarm bell for some toxic substance, especially CO);
- 5) He finally got the results four days before the child died in the room, but;

6) He sat on them for a week and by the time he finally sent them out to the local police; the child was had been killed and his mother permanently injured.

That's a tragic story, all right. And as you can imagine, the two families are suing everyone in sight that had anything to do with any of that, and I would too if I had lost a family member. Meanwhile, the DA also charged the head of the hotel management group with three counts of manslaughter, and all of those cases are still on going.

That's just one example of how tragic things can happen when we don't do everything possible to ensure people's safety. But if you do just a little bit of research, you'll see how frighteningly common that is.

So I know you'll want to address the Hi-Flow sensor failure issue immediately.

As I suggested at the start, let's do it this week. I can go up and meet with EPA tomorrow or Friday, and if you can't be there in person, you can call in, and you can have any interested parties from EDF or your production committees call in as well. i know everyone's busy, but this won't take more than an hour, and I think we should all be willing to make that much time for such a critical issue.

Just	let me	know v	vhen	the	best	tıme	tor	all	ot	you	1S.
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Thanks,

Touche'

To: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]

Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]

From: McKittrick, Alexis

**Sent:** Tue 12/15/2015 5:58:21 PM

Subject: FW: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

;;;; FYI

From: Touche Howard [mailto:touche.howard@indacoaqs.com]

Sent: Tuesday, December 15, 2015 12:48 PM

To: allen@che.utexas.edu

Cc: McKittrick, Alexis; terri\_shires@aecom.com; Weitz, Melissa; Gunning, Paul; McCabe, Janet; RAlvarez@edf.org; shamburg@edf.org; Fernandez, Roger; rharriss@edf.org; ritterk@api.org; dnelson@edf.org; sedlak-office@est.acs.org; dmccabe@catf.us; dlyon@edf.org; Maxwell, Dave (Austin); dschroeder@catf.us; dzavala@edf.org; Chuck Kolb; Gamas, Julia; linda.lee@arb.ca.gov; bmordick@nrdc.org; amrowka@arb.ca.gov; casey.pickering@erg.com; Wisetiawa@arb.ca.gov; Smith, James-D; Snyder, Jennifer; michael.ege@tceq.texas.gov; paige.sprague@tceq.texas.gov; adam.pacsi@chevron.com; Rees, Jeff; matt.harrison@aecom.com; alr@andrew.cmu.edu; awilcox@harcresearch.org; andres.restrepo@sierraclub.org; gabrielle.petron@noaa.gov; natalie.spiegel@sierraclub.org; nathan.matthews@sierraclub.org; rsawyer@me.berkeley.edu; Ganapathy, Roopa (EC/EC); vgowrishankar@nrdc.org; dan.hill@pe.tamu.edu; Matthew.Fraser@asu.edu; seinfeld@caltech.edu

Subject: Re: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

Dave --

Just to follow up on the safety issue, I did a news media search to see what the current state of natural gas industry safety is, because if fires and explosions have been eliminated over time, then my fears would be groundless. But, it turned out to be much worse than I expected. It looks like there have been at least 33 explosions or fires at natural gas facilities over the past five years, killing 11 people and injuring 126 others. You can't tell the cause of all these incidents from the media reports, but it's clear that it's still true that natural gas facilities can and do blow up.

So the issue of safety is still very relevant. But even if it weren't, I'm sure you and Matt would want to address this issue immediately, just for the health and environmental aspects. If nothing else, I believe companies can start their 2016 Subpart W reporting measurements in January, and since two reporting years have gone by since this problem came to light, I think we can all agree that we don't want to let another year go by that could be affected by Hi-Flow sensor failure.

Thanks,

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Now that the EPA is considering using your initial EDF study at production sites (published in PNAS in 2013) and your follow-up study on pneumatic controllers (published in ES&T in 2014), it's critical that we resolve the Hi-Flow sensor failure and other quality assurance issues surrounding those studies as soon as possible. The quickest way to do that is for us to directly discuss these issues with EPA, and I think once you understand the evidence, you'll be able to see the

problems immediately. To that end, let's try to get together tomorrow or Friday. (Melissa and Alexis - I can come up and meet with you either day, and if Dave can't make it, he can call in.)

My biggest concern is safety -- having an instrument that reports natural gas leaks far lower than they actually are is clearly a huge safety issue, and as long as you tell people that this problem didn't occur in your work, it will be very hard for anyone to take it seriously. Meanwhile, for you and EPA, this also represents important health and environmental concerns. And of course since you were chair of the EPA Science Advisory Board while you were conducting this research, and the Hi-Flow sampler is one of the methods approved by EPA to make measurements for their greenhouse gas reporting program under Subpart W, I'm sure you feel a special responsibility to address these issues as soon as possible.

I've attached my ESE paper outlining the problems in your initial 2013 production study as well as my letter and your response about the 2014 study. I've also attached a reply that I wrote in response to your commentary on my paper in ESE, because even though you withdrew that commentary after seeing my response, I think my response did clarify some of the issues.

Since we unfortunately haven't had an opportunity to discuss these issues directly, I'll summarize the evidence here and what I believe are your counterpoints, based on your reviews of my paper and the commentary you submitted. I also want to allay your concerns, which you've stated to others, that I'm raising these issues because I want to sell my own samplers or services. I'm only wrapping up loose ends now, and after this I won't be working in this area any more.

The first issue is sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS), where it can fail to transition from the low range (0 to 5% gas) catalytic oxidation sensor to the high range (5 to 100% gas) thermal conductivity detector, which can cause the sampler to report large leaks as being much smaller that they are. We don't know why this happens, but there's no question that it can, because we demonstrated it in three different instruments, including yours. It doesn't seem to occur for pure methane streams, but we've seen it in the field for gas streams with methane content as high as 91% (J. Air Waste Manag. Assoc. 65:856–862. doi: 10.1080/10962247.2015.1025925).

The effect of this problem is clear in your Phase I data, which I've plotted below showing emission rate as a function of site methane composition. As you can see, most of the high emitters only show up at sites with high methane compositions, and there's no reason that should happen in the real world, especially when you consider that it occurs for several different types of sources.

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Now I believe your counter argument is that this phenomenon is due to air pollution control regulations reducing emissions in the Rocky Mountain region, where the methane content of the gas is lower as well. However, several things tell us that's not the cause of the trend in the figure above. First, even when you take the Rocky Mountain region out of the analysis, there's still far more high emitters at sites with higher methane content. Second, even within just the Appalachia region, the occurrence of high emitters increases dramatically over a very narrow range of site methane compositions, from 95% to 98% methane (shown below). What that tells us is that sampler can start seeing some of the high emitters once methane composition is in the range of 95%, but is still missing a lot of them until methane composition gets up to the 97 to 98% range. This is also an extremely important indicator that this problem could be occurring even for gas streams with methane content above 95%, meaning the problem could occur in all segments of the natural gas industry.

Finally, your emissions measurements made by tracer technique confirm that sensor failure occurred and that the trend of emission rate vs concentration is not caused by regional differences. Now, in your comment you said you found my analysis of your tracer data complex, probably because I showed how Hi-Flow measurements got lower and lower than the tracer measurements for sites with fewer estimated emissions from sources like tanks. So I've simplified that analysis, and just removed the two sites that had 98% or more of the emissions estimated as opposed to measured. This comparison of the tracer versus on site Hi-Flow measurements is shown below.

So clearly, as you've suggested, there are regional differences, assuming these sites are representative. The tracer data shows that the emissions from sites in the Rocky Mountain (RM) region are lower than the sites in the Mid-continent (MC) region, although in the same range as 75% of the Appalachia (AP) sites. But just as clearly, the sites with lower methane content (Rocky Mountain and Mid-continent, where sensor failure might occur consistently) have far lower (about a factor of two) Hi-Flow measurements than the tracer technique. Meanwhile, the sites with high methane content (Appalachia, where the problem isn't expected to occur) have Hi-Flow measurements close to or exceeding the tracer measurements. Keep in mind that because some of the on-site data comes from estimates, this masks the magnitude of the error, but at least this is a simple comparison.

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experimental errors, then we'd expect roughly 50% of the sites to have tracer greater than Hi-Flow, and 50% lower. It's actually a 70/30 split, but the remarkable thing is that we can predict which region will have tracer greater than Hi-Flow and which won't. This is pretty much the same thing as me being able to walk into a bar and betting the barmaid that if I stand on her side of the bar and flip a coin it will always come up heads, but if I stand on my side of the bar and flip a coin, it will always come up tails. And in between drinks, we run that experiment, and it turns out that I'm right 16 out of 17 times.

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In any case, I think this shows that it probably would have been better to involve me directly in discussions you had with the EDF committees and others about this problem after I brought it to you in October of 2013, because I could have explained immediately why the reasons you thought this problem didn't affect your Phase I data were incorrect. It has been puzzling to me that given the overwhelming evidence, that this problem wasn't obvious to you, but I'm wondering if that might be due to inexperience with field measurements. As an example, in both your Phase I and Phase II papers, you incorrectly describe the

operation of the Hi-Flow sensors, and without understanding that the Hi-Flow has to to switch back and forth between sensors to make accurate measurements, it's probably impossible for you to understand the sensor transition problem.

I'm wondering if inexperience might have also led to the problems in your Phase II work as well. It's a harsh environment for meters to be transported between field sites on rough roads and have raw natural gas run through them, and I think most people with experience in field measurements would have built in a routine testing of those meters during the project, rather than just check them before and after the project as you did. When you're out in the field looking at pneumatics, you see lots of them with oil or other hydrocarbon accumulations, so it's easy to picture how the meter sensor could get fouled, as yours did. I would think at least a weekly multi-point meter calibration and a daily single point flow check would be required to ensure accurate measurements. which is what was done during the EDF WSU distribution work. The Indaco Hi-Flows that were used in that project have a very similar flow measurement system to your Fox meter, which is a thermal element in a tube, and even though the distribution study was a much less harsh environment, where leaks of relatively clean distribution gas were measured and the flow system dilutes those leaks with air before the gas hits the sensors, full scale weekly calibrations and single point daily flow checks were conducted.

Now, as you remember, while that project was ongoing, I found that one of your two primary meters was measuring too low by a factor of three. Well, that's not a surprise, given the harsh environment. I haven't used the particular meter that you were using before, but I did look at the manual for it, and it clearly states that a dirty sensor will cause measurements to be too low.

But I think how you addressed that issue indicates further inexperience. Since you don't mention the meter test I made showing it was a factor of three too low in your paper, but only indicate that you found the problem post project, it appears that you just kept using the meter, without trying to figure out what was wrong with it, and without instituting any additional meter checks.

Instead, it wasn't until the end of the project that you did any further checks, and at that point the response of the meter had changed again, to being low by about 34%. In order to understand more about the problem, you tried to use your Hi-Flow data to validate the meter results. Now your laboratory comparisons of the two for the most part are excellent and agree within 10%. But surprisingly, your field comparisons of the Hi-Flow to the meters are far worse. For measurements where either one or the other was >0.5 scfh, only 4 out of 19 (21%) are within 25%, and even for measurements >6 scfh, only 3 out of 10 (30%) are within 25% of each other. You do allude to the possibility of leaks affecting the measurements but don't give any indication that you tried to quantify the leaks that you think affected the measurements.

For comparison, in the WSU distribution work, where direct and tracer

measurements were compared, 10 out of 14 (71%) were within 50% of each other, over a range of about 0.6 to 56 scfh. Now I would have liked that to be better, but I think I understand some of the challenges, one being that some of those that are far off are at really low emission rates, so missing just one source could throw you off a lot. But keep in mind, that's measuring the whole M&R facility or an underground leak, and comparing it to a downwind tracer flux measurement, so you have lots of challenges including multiple measurements at the facility and tracer source configurations.

But for your pneumatic work, while doing a direct comparison of Hi-Flow to meters, for just single sources, only 7 of 19 (37%) were within 50% of each other over a similar emission range of 0.5 to 60 scfh.

So unfortunately your comparison of High Flow to meters should not have been used to justify correcting your meter, especially when my direct test of that meter's performance mid-project showed it was much worse than the post project check indicated.

Another indication of the meter uncertainty came from Matt Harrison, who was present when I found that your meter was reading a factor of three too low, and said at the time, "Yeah, everyone knows that meter is flaky. You can hook it up to an pneumatic and hear the pneumatic fire but not see anything on the meter."

Now, along with the sensor getting dirty, your meter measurements might have been affected by two other factors mentioned in the meter manual. These meters are supposed to be oriented upright, and you need a certain length of straight run (I think for the meter you were using, six inches) before the meter. However, it appears, looking at a slide from the presentation about the project on your website shown below, that those conditions weren't met either. Although you can see in the close up that the meter is marked with a label that says "Keep Upright and Level", that condition hasn't been met in either configuration pictured. Additionally, the entrance length doesn't appear to meet the required distance either.

I think these issues were all compounded by perhaps your lack of experience with what information editors and reviewers need to evaluate field measurement papers. Your meter problem is only mentioned in a footnote on page 59 of your Supplementary Information, and was likely missed by the editor and reviewers. But if reviewers with substantial field experience understood the entire picture -- that you only checked your calibration before and after the project, that there was an undisclosed mid project test showing meter performance was much worse than

the correction you applied, that after you were shown one meter was faulty in the middle of the project that you simply continued to use it without finding out what was wrong or instituting improved calibration checks, "that everyone knew that meter was flaky," and that your Hi-Flow and meter field measurements don't compare very well -- I believe they would conclude that you didn't meet the fundamentals of quality assurance and that the paper would have been rejected.

So unfortunately neither the Phase I or Phase II data should be used by EPA. Although there may be large uncertainties in inventories, we shouldn't include numbers that have such large question marks. Think about cancer treatments. Those have very uncertain outcomes, but that doesn't mean that we don't want good quality assurance in cancer research or in the dosages of drugs or radiation therapy that are used. And when you consider the broad environmental impact of air toxics to the communities surrounding oil and gas facilities as well as the consequences of climate change, it's critical that we use the best data possible.

And as I said at the start, safety is my biggest concern regarding the HiFlow sensor failure, and I think perhaps again inexperience has caused you not to fully appreciate what a critical safety issue this is. I've spent a lot of time measuring leak rates at natural gas facilities, and I've seen facility personnel shut down units in order to address large leaks that we found due to safety concerns -- I've done lots of leak measurement programs that were focused more on the integrity of the facility rather than the issue of greenhouse gases. Additionally, we don't know how the sampler might be used in the future -- for instance, given GTI's and WSU's work in distribution, it might be used to rank leaks for repair in that segment (even though the WSU study used a different version of the sampler not affected by this problem).

James Reason wrote a really great book about the Swiss cheese theory of disasters (Reason, James (1997). Managing the risks of organizational accidents.

Aldershot: Ashgate. <u>ISBN 1840141042</u>.) which is widely studied in aviation, engineering, and the fire service. In it he describes how the really terrible things that happen usually occur because there have been failures on several levels, and those failures line up to let something really bad happen.

We had a terrible example of that happen here in North Carolina a couple of years ago. A couple checked into a hotel, and the next morning they were dead. Seven weeks later, an 11 year old boy died in the same room, and although his mother survived, she had permanent brain damage.

All of that could have been avoided, because they were killed by carbon monoxide. You might have seen this on 20/20:

 $\underline{http://abcnews.go.com/US/north-carolina-best-western-room-225-open-deaths/story?id=21564280}$ 

Here's how it all lined up:

- 1) The hotel pulled an old pool heater out of another property and installed it at that hotel, even though it was at the end of its life, meaning it was inefficient and was at risk for producing more carbon monoxide, and they didn't get a city inspection permit;
- 2) The vent pipe was corroded, and let the CO escape under the room where everyone was killed;
- 3) There were holes in the fire place in the room that let more CO in that would have come in otherwise:
- 4) The CO detectors that were supposed to have been installed in the rooms were actually natural gas detectors, installed by mistake.

So that's what killed the first couple.

But here's why the little boy died:

- 1) Three days after the couple was killed, a family in the room above got really sick, and complained, but the hotel didn't pay attention;
- 2) The family of the first couple raised warnings with the hotel and police that it might be CO and again no one paid attention;
- 3) The medical examiner didn't visit the scene of the first couple and see that the wife had thrown up (an important clue in CO poisoning)
- 4) He also didn't put an expedite order on their blood work, so it sat for 40 days (two people simultaneously dead in an enclosed space -- a huge alarm bell for some toxic substance, especially CO);
- 5) He finally got the results four days before the child died in the room, but;
- 6) He sat on them for a week and by the time he finally sent them out to the local police; the child was had been killed and his mother permanently injured.

That's a tragic story, all right. And as you can imagine, the two families are suing everyone in sight that had anything to do with any of that, and I would too if I had lost a family member. Meanwhile, the DA also charged the head of the hotel management group with three counts of manslaughter, and all of those cases are still on going.

That's just one example of how tragic things can happen when we don't do everything possible to ensure people's safety. But if you do just a little bit of

research, you'll see how frighteningly common that is.

So I know you'll want to address the Hi-Flow sensor failure issue immediately.

As I suggested at the start, let's do it this week. I can go up and meet with EPA tomorrow or Friday, and if you can't be there in person, you can call in, and you can have any interested parties from EDF or your production committees call in as well. i know everyone's busy, but this won't take more than an hour, and I think we should all be willing to make that much time for such a critical issue.

Just	let me	know w	hen t	the	best	time	for	all	of	you	is.
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Thanks,

Touche'

To: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]

From: Weitz, Melissa

**Sent:** Mon 12/14/2015 9:43:58 PM

**Subject:** FW: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

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"My favorite was was told to me by an operator who was the son of a compressor station manager. When he was growing up, they lived near the station, and one night after dinner he wanted to go to the mechanic's shop at the site to work on his car. Oh, no, his mother says, it's your turn to do the dishes. So there he is, sulking at the sink, when the station blows up, basically right in front of him as he's watching out the kitchen window, and destroying with it the mechanic's shop where he would have been if his mother hadn't made him wash dishes."

From: Touche Howard [mailto:touche.howard@indacoaqs.com]

Sent: Monday, December 14, 2015 4:42 PM

To: allen@che.utexas.edu

Cc: McKittrick, Alexis; terri\_shires@aecom.com; Weitz, Melissa; Gunning, Paul; McCabe, Janet; RAlvarez@edf.org; shamburg@edf.org; Fernandez, Roger; rharriss@edf.org; ritterk@api.org; dnelson@edf.org; sedlak-office@est.acs.org; dmccabe@catf.us; dlyon@edf.org; Maxwell, Dave (Austin); dschroeder@catf.us; dzavala@edf.org; Chuck Kolb; Gamas, Julia; linda.lee@arb.ca.gov; bmordick@nrdc.org; amrowka@arb.ca.gov; casey.pickering@erg.com; Wisetiawa@arb.ca.gov; Smith, James-D; Snyder, Jennifer; michael.ege@tceq.texas.gov; paige.sprague@tceq.texas.gov; adam.pacsi@chevron.com; Jeff.Rees@pxd.com; matt.harrison@aecom.com; alr@andrew.cmu.edu; awilcox@harcresearch.org; andres.restrepo@sierraclub.org; gabrielle.petron@noaa.gov; natalie.spiegel@sierraclub.org; nathan.matthews@sierraclub.org; rsawyer@me.berkeley.edu; Ganapathy, Roopa (EC/EC); vgowrishankar@nrdc.org; dan.hill@pe.tamu.edu; Matthew.Fraser@asu.edu; seinfeld@caltech.edu

Subject: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

Dave --

I think that Matt's statement of "I see no safety issue" (regarding the Bacharach Hi-Flow sampler's problem of reporting leaks as far smaler than they actually are) might have resulted from your team either not being aware of all the potential uses of the Hi-Flow sampler or from having a somewhat narrow view of what problems can compromise safety.

Probably half of the leak measurement programs I've conducted were for private companies whose primary goals were to reduce gas loss and to improve safety, as opposed to cataloging greenhouse gas emissions. At 1 to 2% of all the facilities I've been to, we found leaks that caused the operators to immediately shut down equipment. Examples include leakage into compressor distance pieces that was large enough to cause back pressure into the engine crankcase, flanges that had a leak rate large enough that it might cause further gasket erosion and failure, and large leaks at welds on compressor fuel gas systems that might catastrophically fail or be large enough to reach an ignition source due to induced sparking at vibrating components in the ignition coil area.

Did we prevent explosions in those cases? We'll never know, but we did provide one layer of

defense by eliminating imminently dangerous conditions. So if only 1% of facilities have a dangerous underlying condition that might go undiscovered if a Hi-Flow sampler fails, is it really worth an hour of your time to address this issue? I think most people would say yes.

Even high flow surveys that focus on research or greenhouse gas reporting have the opportunity to reduce dangerous conditions if done properly. I think the protocol in most (hopefully all) leak measurement programs, whatever their focus, is to immediately alert facility operators of any hazardous conditions found. So it's certainly not acceptable to leave hazards unidentified due to sampler failure just because many surveys are focused on greenhouse gas emissions instead of facility integrity.

Other instances where sampler failure might affect safety are when it is used to make an on the spot repair decision when a leak is discovered by an operator and when it is used to survey facilities being put into initial service. And as I pointed out previously, we don't know all the ways a sampler might be used now or in the future. If, for instance, it were used to rank distribution leaks for repair, under reporting large leaks could have tragic consequences.

Now you might think that other indications, such as an IR camera, or auditory, visual, and olfactory (AVO) detection would provide clues that a leak was much larger than the sampler indicated, but most people just don't have that level of experience, and a noisy and/or hot environment can make it even more difficult. There's an excellent example of this in your Phase II pneumatic work, where Device No. XQ01-PC04 was measured both by Hi-Flow (0.13 scfh) and meter (37.37 scfh), and you assume the Hi-Flow measurement is too low due to the device not being adequately enclosed. However, this device was a continuous bleed controller with a high emission rate (in the top 20% of the continuous controllers you measured). Consequently, even though the Hi-Flow was making an easy to read steady state measurement for most of that interval, your technicians did not recognize that the Hi-Flow reading was almost 300 times too low (if they had, they would have certainly attempted to correct the problem while the measurement was being made). This highlights that even people who had been making these type of measurements day after day during an extensive field program could not accurately judge emission rates without reliable instrumentation.

And although safety systems like gas detectors or hot work permits provide one line of defense, they can't always protect the facility from a leak that could have been fixed but wasn't, and then either failed catastrophically or found an ignition source before automatic detection shut down equipment. Having been to so many facilities, I've heard lots of stories of past explosions. My favorite was was told to me by an operator who was the son of a compressor station manager. When he was growing up, they lived near the station, and one night after dinner he wanted to go to the mechanic's shop at the site to work on his car. Oh, no, his mother says, it's your turn to do the dishes. So there he is, sulking at the sink, when the station blows up, basically right in front of him as he's watching out the kitchen window, and destroying with it the mechanic's shop where he would have been if his mother hadn't made him wash dishes.

Unfortunately, not all the stories had a happy ending like that.

I hope this provides a better perspective on the safety issues involved.

Thanks,

Touche'

On Wed, Dec 9, 2015 at 8:56 PM, Harrison, Matt <<u>matt.harrison@aecom.com</u>> wrote:

I see no safety issue. HiFlows are never used as safety devices to my knowledge

Matt Harrison

512-694-0572

Sent from my iPhone

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But I think how you addressed that issue indicates further inexperience. Since you don't mention the meter test I made showing it was a factor of three too low in your paper, but only indicate that you found the problem post project, it appears that you just kept using the meter, without trying to figure out what was wrong with it, and without instituting any additional meter checks.

Instead, it wasn't until the end of the project that you did any further checks, and at that point the response of the meter had changed again, to being low by about 34%. In order to understand more about the problem, you tried to use your Hi-Flow data to validate the meter results. Now your laboratory comparisons of the two for the most part are excellent and agree within 10%. But surprisingly, your field comparisons of the Hi-Flow to the meters are far worse. For measurements where either one or the other was >0.5 scfh, only 4 out of 19 (21%) are within 25%, and even for measurements >6 scfh, only 3 out of 10 (30%) are within 25% of each other. You do allude to the possibility of leaks affecting the measurements but don't give any indication that you tried to quantify the leaks that you think affected the measurements.

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But for your pneumatic work, while doing a direct comparison of Hi-Flow to meters, for just single sources, only 7 of 19 (37%) were within 50% of each other over a similar emission range of 0.5 to 60 scfh.

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Now, along with the sensor getting dirty, your meter measurements might have been affected by two other factors mentioned in the meter manual. These meters are supposed to be oriented upright, and you need a certain length of straight run (I think for the meter you were using, six inches) before the meter. However, it appears, looking at a slide from the presentation about the project on your website shown below, that those conditions weren't met either. Although you can see in the close up

that the meter is marked with a label that says "Keep Upright and Level", that condition hasn't been met in either configuration pictured. Additionally, the entrance length doesn't appear to meet the required distance either.

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And as I said at the start, safety is my biggest concern regarding the HiFlow sensor failure, and I think perhaps again inexperience has caused you not to fully appreciate what a critical safety issue this is. I've spent a lot of time measuring leak rates at natural gas facilities, and I've seen facility personnel shut down units in order to address large leaks that we found due to safety concerns -- I've done lots of leak measurement programs that were focused more on the integrity of the facility rather than the issue of greenhouse gases. Additionally, we don't know how the sampler might be used in the future -- for instance, given GTI's and WSU's work in distribution, it might be used to rank leaks for repair in that segment (even though the WSU study used a different version of the sampler not affected by this problem).

James Reason wrote a really great book about the Swiss cheese theory of disasters (Reason, James (1997). Managing the risks of organizational accidents. Aldershot: Ashgate. ISBN 1840141042.) which is widely studied in aviation, engineering, and the

fire service. In it he describes how the really terrible things that happen usually occur because there have been failures on several levels, and those failures line up to let something really bad happen.

We had a terrible example of that happen here in North Carolina a couple of years ago. A couple checked into a hotel, and the next morning they were dead. Seven weeks later, an 11 year old boy died in the same room, and although his mother survived, she had permanent brain damage.

All of that could have been avoided, because they were killed by carbon monoxide. You might have seen this on 20/20:

http://abcnews.go.com/US/north-carolina-best-western-room-225-open-deaths/story?id=21564280

Here's how it all lined up:

- 1) The hotel pulled an old pool heater out of another property and installed it at that hotel, even though it was at the end of its life, meaning it was inefficient and was at risk for producing more carbon monoxide, and they didn't get a city inspection permit;
- 2) The vent pipe was corroded, and let the CO escape under the room where everyone was killed;
- 3) There were holes in the fire place in the room that let more CO in that would have come in otherwise;
- 4) The CO detectors that were supposed to have been installed in the rooms were actually natural gas detectors, installed by mistake.

So that's what killed the first couple.

But here's why the little boy died:

- 1) Three days after the couple was killed, a family in the room above got really sick, and complained, but the hotel didn't pay attention;
- 2) The family of the first couple raised warnings with the hotel and police that it might be CO and again no one paid attention;
- 3) The medical examiner didn't visit the scene of the first couple and see that the wife had thrown up (an important clue in CO poisoning)
- 4) He also didn't put an expedite order on their blood work, so it sat for 40 days (two people simultaneously dead in an enclosed space -- a huge alarm bell for some toxic substance, especially CO);

- 5) He finally got the results four days before the child died in the room, but;
- 6) He sat on them for a week and by the time he finally sent them out to the local police; the child was had been killed and his mother permanently injured.

That's a tragic story, all right. And as you can imagine, the two families are suing everyone in sight that had anything to do with any of that, and I would too if I had lost a family member. Meanwhile, the DA also charged the head of the hotel management group with three counts of manslaughter, and all of those cases are still on going.

That's just one example of how tragic things can happen when we don't do everything possible to ensure people's safety. But if you do just a little bit of research, you'll see how frighteningly common that is.

So I know you'll want to address the Hi-Flow sensor failure issue immediately.

As I suggested at the start, let's do it this week. I can go up and meet with EPA tomorrow or Friday, and if you can't be there in person, you can call in, and you can have any interested parties from EDF or your production committees call in as well. i know everyone's busy, but this won't take more than an hour, and I think we should all be willing to make that much time for such a critical issue.

Just let me	know when	the best	time for	all of	vou is.

Thanks,

Touche'

To: Irving, Bill[Irving.Bill@epa.gov]

From: Weitz, Melissa

**Sent:** Mon 12/14/2015 10:31:25 PM

**Subject:** RE: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

,,,,

No need to read—I haven't even made it through the whole thing. I can give you a summary tomorrow

From: Weitz, Melissa

Sent: Monday, December 14, 2015 5:30 PM

**To:** Irving, Bill

Subject: FW: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

A preview for tomorrow.

From: Touche Howard [mailto:touche.howard@indacoags.com]

Sent: Monday, December 14, 2015 4:42 PM

To: allen@che.utexas.edu

Cc: McKittrick, Alexis < McKittrick.Alexis@epa.gov >; terri shires@aecom.com; Weitz, Melissa < Weitz.Melissa@epa.gov >; Gunning, Paul < Gunning.Paul@epa.gov >; McCabe, Janet < McCabe.Janet@epa.gov >; RAlvarez@edf.org; shamburg@edf.org; Fernandez, Roger < Fernandez.Roger@epa.gov >; rharriss@edf.org; ritterk@api.org; dnelson@edf.org; sedlak-office@est.acs.org; dmccabe@catf.us; dlyon@edf.org; Maxwell, Dave (Austin) < dave.maxwell@aecom.com >; dschroeder@catf.us; dzavala@edf.org; Chuck Kolb < kolb@aerodyne.com >; Gamas, Julia < Gamas.Julia@epa.gov >; linda.lee@arb.ca.gov; bmordick@nrdc.org; amrowka@arb.ca.gov; casey.pickering@erg.com; Wisetiawa@arb.ca.gov; Smith, James-D < Smith.James-D@epa.gov >; Snyder, Jennifer < Snyder.Jennifer@epa.gov >; michael.ege@tceq.texas.gov; paige.sprague@tceq.texas.gov; adam.pacsi@chevron.com; Jeff.Rees@pxd.com; matt.harrison@aecom.com; alr@andrew.cmu.edu; awilcox@harcresearch.org; andres.restrepo@sierraclub.org; gabrielle.petron@noaa.gov; natalie.spiegel@sierraclub.org; nathan.matthews@sierraclub.org; rsawyer@me.berkeley.edu; Ganapathy, Roopa (EC/EC) < Roopa.Ganapathy@canada.ca >; ygowrishankar@nrdc.org; dan.hill@pe.tamu.edu; Matthew.Fraser@asu.edu; seinfeld@caltech.edu

Subject: Safety Issues Regarding Hi-Flow Sampler Sensor Failure

Dave --

I think that Matt's statement of "I see no safety issue" (regarding the Bacharach Hi-Flow sampler's problem of reporting leaks as far smaler than they actually are) might have resulted from your team either not being aware of all the potential uses of the Hi-Flow sampler or from having a somewhat narrow view of what problems can compromise safety.

Probably half of the leak measurement programs I've conducted were for private companies whose primary goals were to reduce gas loss and to improve safety, as opposed to cataloging greenhouse gas emissions. At 1 to 2% of all the facilities I've been to, we found leaks that caused the operators to immediately shut down equipment. Examples include leakage into compressor distance pieces that was large enough to cause back pressure into the engine crankcase, flanges that had a leak rate large enough that it might cause further gasket erosion and failure, and large

leaks at welds on compressor fuel gas systems that might catastrophically fail or be large enough to reach an ignition source due to induced sparking at vibrating components in the ignition coil area.

Did we prevent explosions in those cases? We'll never know, but we did provide one layer of defense by eliminating imminently dangerous conditions. So if only 1% of facilities have a dangerous underlying condition that might go undiscovered if a Hi-Flow sampler fails, is it really worth an hour of your time to address this issue? I think most people would say yes.

Even high flow surveys that focus on research or greenhouse gas reporting have the opportunity to reduce dangerous conditions if done properly. I think the protocol in most (hopefully all) leak measurement programs, whatever their focus, is to immediately alert facility operators of any hazardous conditions found. So it's certainly not acceptable to leave hazards unidentified due to sampler failure just because many surveys are focused on greenhouse gas emissions instead of facility integrity.

Other instances where sampler failure might affect safety are when it is used to make an on the spot repair decision when a leak is discovered by an operator and when it is used to survey facilities being put into initial service. And as I pointed out previously, we don't know all the ways a sampler might be used now or in the future. If, for instance, it were used to rank distribution leaks for repair, under reporting large leaks could have tragic consequences.

Now you might think that other indications, such as an IR camera, or auditory, visual, and olfactory (AVO) detection would provide clues that a leak was much larger than the sampler indicated, but most people just don't have that level of experience, and a noisy and/or hot environment can make it even more difficult. There's an excellent example of this in your Phase II pneumatic work, where Device No. XQ01-PC04 was measured both by Hi-Flow (0.13 scfh) and meter (37.37 scfh), and you assume the Hi-Flow measurement is too low due to the device not being adequately enclosed. However, this device was a continuous bleed controller with a high emission rate (in the top 20% of the continuous controllers you measured). Consequently, even though the Hi-Flow was making an easy to read steady state measurement for most of that interval, your technicians did not recognize that the Hi-Flow reading was almost 300 times too low (if they had, they would have certainly attempted to correct the problem while the measurement was being made). This highlights that even people who had been making these type of measurements day after day during an extensive field program could not accurately judge emission rates without reliable instrumentation.

And although safety systems like gas detectors or hot work permits provide one line of defense, they can't always protect the facility from a leak that could have been fixed but wasn't, and then either failed catastrophically or found an ignition source before automatic detection shut down equipment. Having been to so many facilities, I've heard lots of stories of past explosions. My favorite was was told to me by an operator who was the son of a compressor station manager. When he was growing up, they lived near the station, and one night after dinner he wanted to go to the mechanic's shop at the site to work on his car. Oh, no, his mother says, it's your turn to do the dishes. So there he is, sulking at the sink, when the station blows up, basically right in front of him as he's watching out the kitchen window, and destroying with it the mechanic's shop

where he would have been if his mother hadn't made him wash dishes.

Unfortunately, not all the stories had a happy ending like that.

I hope this provides a better perspective on the safety issues involved.

Thanks,

Touche'

On Wed, Dec 9, 2015 at 8:56 PM, Harrison, Matt < matt.harrison@aecom.com > wrote:

I see no safety issue. HiFlows are never used as safety devices to my knowledge

Matt Harrison

512-694-0572

Sent from my iPhone

On Dec 9, 2015, at 2:25 PM, "Touche Howard" < touche.howard@indacoaqs.com > wrote:

Dave --

Now that the EPA is considering using your initial EDF study at production sites (published in PNAS in 2013) and your follow-up study on pneumatic controllers (published in ES&T in 2014), it's critical that we resolve the Hi-Flow sensor failure and other quality assurance issues surrounding those studies as soon as possible. The quickest way to do that is for us to directly discuss these issues with EPA, and I think once you understand the evidence, you'll be able to see the problems immediately. To that end, let's try to get together tomorrow or Friday. (Melissa and Alexis - I can come up and meet with you either day, and if Dave can't make it, he can call in.)

My biggest concern is safety -- having an instrument that reports natural gas leaks far lower than they actually are is clearly a huge safety issue, and as long as you tell people that this problem didn't occur in your work, it will be very hard for anyone to take it seriously. Meanwhile, for you and EPA, this also represents important health and environmental concerns. And of course since you were chair of the EPA Science Advisory Board while you were conducting this research, and the Hi-Flow sampler is one of the methods approved by EPA to make measurements for their greenhouse gas reporting program under Subpart W, I'm sure you feel a special responsibility to address these issues as soon as possible.

I've attached my ESE paper outlining the problems in your initial 2013 production study as well as my letter and your response about the 2014 study. I've also attached a reply that I wrote in response to your commentary on my paper in ESE, because even

though you withdrew that commentary after seeing my response, I think my response did clarify some of the issues.

Since we unfortunately haven't had an opportunity to discuss these issues directly, I'll summarize the evidence here and what I believe are your counterpoints, based on your reviews of my paper and the commentary you submitted. I also want to allay your concerns, which you've stated to others, that I'm raising these issues because I want to sell my own samplers or services. I'm only wrapping up loose ends now, and after this I won't be working in this area any more.

The first issue is sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS), where it can fail to transition from the low range (0 to 5% gas) catalytic oxidation sensor to the high range (5 to 100% gas) thermal conductivity detector, which can cause the sampler to report large leaks as being much smaller that they are. We don't know why this happens, but there's no question that it can, because we demonstrated it in three different instruments, including yours. It doesn't seem to occur for pure methane streams, but we've seen it in the field for gas streams with methane content as high as 91% (J. Air Waste Manag. Assoc. 65:856–862. doi: 10.1080/10962247.2015.1025925).

The effect of this problem is clear in your Phase I data, which I've plotted below showing emission rate as a function of site methane composition. As you can see, most of the high emitters only show up at sites with high methane compositions, and there's no reason that should happen in the real world, especially when you consider that it occurs for several different types of sources.

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Now I believe your counter argument is that this phenomenon is due to air pollution control regulations reducing emissions in the Rocky Mountain region, where the methane content of the gas is lower as well. However, several things tell us that's not the cause of the trend in the figure above. First, even when you take the Rocky Mountain region out of the analysis, there's still far more high emitters at sites with higher methane content. Second, even within just the Appalachia region, the occurrence of high emitters increases dramatically over a very narrow range of site methane compositions, from 95% to 98% methane (shown below). What that tells us is that sampler can start seeing some of the high emitters once methane composition is in the range of 95%, but is still missing a lot of them until methane composition gets up to the 97 to 98% range. This is also an extremely important indicator that this problem could be occurring even for gas streams with methane content above 95%, meaning the problem could occur in all segments of the natural gas industry.

Finally, your emissions measurements made by tracer technique confirm that sensor failure occurred and that the trend of emission rate vs concentration is not caused by regional differences. Now, in your comment you said you found my analysis of your tracer data complex, probably because I showed how Hi-Flow measurements got lower and lower than the tracer measurements for sites with fewer estimated emissions from sources like tanks. So I've simplified that analysis, and just removed the two sites that had 98% or more of the emissions estimated as opposed to measured. This comparison of the tracer versus on site Hi-Flow measurements is shown below.

So clearly, as you've suggested, there are regional differences, assuming these sites are representative. The tracer data shows that the emissions from sites in the Rocky Mountain (RM) region are lower than the sites in the Mid-continent (MC) region, although in the same range as 75% of the Appalachia (AP) sites. But just as clearly, the sites with lower methane content (Rocky Mountain and Mid-continent, where sensor failure might occur consistently) have far lower (about a factor of two) Hi-Flow measurements than the tracer technique. Meanwhile, the sites with high methane content (Appalachia, where the problem isn't expected to occur) have Hi-Flow measurements close to or exceeding the tracer measurements. Keep in mind that because some of the on-site data comes from estimates, this masks the magnitude of the error, but at least this is a simple comparison.

Now if the variations between the tracer and the Hi-Flow were due to random experimental errors, then we'd expect roughly 50% of the sites to have tracer greater than Hi-Flow, and 50% lower. It's actually a 70/30 split, but the remarkable thing is that we can predict which region will have tracer greater than Hi-Flow and which won't. This is pretty much the same thing as me being able to walk into a bar and betting the barmaid that if I stand on her side of the bar and flip a coin it will always come up heads, but if I stand on my side of the bar and flip a coin, it will always come up tails. And in between drinks, we run that experiment, and it turns out that I'm right 16 out of 17 times.

Now that's a bar bet I'd like to be able to make routinely.

You also said in your unpublished comment to ESE that the testing I conducted on your instrument and others in March of 2013 showed a low occurrence of this problem. That's true of course, but I was surprised you said that, since you know that immediately after we did that testing that I met with some very experienced Hi-Flow technicians who specifically told me that they had fixed some of their samplers that had been reporting leaks too low by upgrading the sampler's software. Since all of the samplers we tested when we tested yours had new generation software, the only real surprise is that we saw any failure at all, and that failure was in your sampler. So even though new software improves the problem, it doesn't fix it completely. Additionally,

there are lots of these samplers around the US and the world using older software, and lots of data that has been collected using samplers prior to software upgrades.

One other argument you made was that your Phase I pneumatic data, made by Hi-Flow, was higher than your Phase II pneumatic data, collected by meter, and if your Hi-Flow had been reporting too low, this should have been the other way around. The reason this isn't true is that your Phase I pneumatic data is clearly an emitter data set (95% of them are emitting) while your Phase II data set is a comprehensive data set (about 21% are actual emitters). So you accidentally excluded sampling zero emitters in Phase I, which biases that data high by a factor of four to five, and offsets any Hi-Flow sensor failure. Additionally, the Phase II data actually shows exactly what I predicted to you it would show -- that the high emitters are more predominant at sites with lower methane compositions when measured by the inline meter as opposed to your Phase I measurements, where the sensor failure caused the high emitters at those sites to be under reported.

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affected by two other factors mentioned in the meter manual. These meters are supposed to be oriented upright, and you need a certain length of straight run (I think for the meter you were using, six inches) before the meter. However, it appears, looking at a slide from the presentation about the project on your website shown below, that those conditions weren't met either. Although you can see in the close up that the meter is marked with a label that says "Keep Upright and Level", that condition hasn't been met in either configuration pictured. Additionally, the entrance length doesn't appear to meet the required distance either.

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So unfortunately neither the Phase I or Phase II data should be used by EPA. Although there may be large uncertainties in inventories, we shouldn't include numbers that have such large question marks. Think about cancer treatments. Those have very uncertain outcomes, but that doesn't mean that we don't want good quality assurance in cancer research or in the dosages of drugs or radiation therapy that are used. And when you consider the broad environmental impact of air toxics to the communities surrounding oil and gas facilities as well as the consequences of climate change, it's critical that we use the best data possible.

And as I said at the start, safety is my biggest concern regarding the HiFlow sensor failure, and I think perhaps again inexperience has caused you not to fully appreciate what a critical safety issue this is. I've spent a lot of time measuring leak rates at natural gas facilities, and I've seen facility personnel shut down units in order to address large leaks that we found due to safety concerns -- I've done lots of leak measurement programs that were focused more on the integrity of the facility rather than the issue of greenhouse gases. Additionally, we don't know how the sampler might be used in the future -- for instance, given GTI's and WSU's work in distribution, it might be used to rank leaks for repair in that segment (even though the WSU study

used a different version of the sampler not affected by this problem).

James Reason wrote a really great book about the Swiss cheese theory of disasters (Reason, James (1997). Managing the risks of organizational accidents. Aldershot: Ashgate. ISBN 1840141042.) which is widely studied in aviation, engineering, and the fire service. In it he describes how the really terrible things that happen usually occur because there have been failures on several levels, and those failures line up to let something really bad happen.

We had a terrible example of that happen here in North Carolina a couple of years ago. A couple checked into a hotel, and the next morning they were dead. Seven weeks later, an 11 year old boy died in the same room, and although his mother survived, she had permanent brain damage.

All of that could have been avoided, because they were killed by carbon monoxide. You might have seen this on 20/20:

 $\frac{http://abcnews.go.com/US/north-carolina-best-western-room-225-open-deaths/story?id=21564280$ 

Here's how it all lined up:

- 1) The hotel pulled an old pool heater out of another property and installed it at that hotel, even though it was at the end of its life, meaning it was inefficient and was at risk for producing more carbon monoxide, and they didn't get a city inspection permit;
- 2) The vent pipe was corroded, and let the CO escape under the room where everyone was killed;
- 3) There were holes in the fire place in the room that let more CO in that would have come in otherwise;
- 4) The CO detectors that were supposed to have been installed in the rooms were actually natural gas detectors, installed by mistake.

So that's what killed the first couple.

But here's why the little boy died:

- 1) Three days after the couple was killed, a family in the room above got really sick, and complained, but the hotel didn't pay attention;
- 2) The family of the first couple raised warnings with the hotel and police that it might be CO and again no one paid attention;
- 3) The medical examiner didn't visit the scene of the first couple and see that the wife

had thrown up (an important clue in CO poisoning)

- 4) He also didn't put an expedite order on their blood work, so it sat for 40 days (two people simultaneously dead in an enclosed space -- a huge alarm bell for some toxic substance, especially CO);
- 5) He finally got the results four days before the child died in the room, but;
- 6) He sat on them for a week and by the time he finally sent them out to the local police; the child was had been killed and his mother permanently injured.

That's a tragic story, all right. And as you can imagine, the two families are suing everyone in sight that had anything to do with any of that, and I would too if I had lost a family member. Meanwhile, the DA also charged the head of the hotel management group with three counts of manslaughter, and all of those cases are still on going.

That's just one example of how tragic things can happen when we don't do everything possible to ensure people's safety. But if you do just a little bit of research, you'll see how frighteningly common that is.

So I know you'll want to address the Hi-Flow sensor failure issue immediately.

As I suggested at the start, let's do it this week. I can go up and meet with EPA tomorrow or Friday, and if you can't be there in person, you can call in, and you can have any interested parties from EDF or your production committees call in as well. i know everyone's busy, but this won't take more than an hour, and I think we should all be willing to make that much time for such a critical issue.

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## **Energy Science & Engineering**

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RESEARCH ARTICLE

# University of Texas study underestimates national methane emissions at natural gas production sites due to instrument sensor failure

Touché Howard

Indaco Air Quality Services, Inc., Durham, North Carolina

#### Keywords

Greenhouse gases, methane, natural gas

#### Correspondence

Touché Howard, Indaco Air Quality Services, Inc., Durham, NC. Tel: (919) 943-9406; E-mail: touche.howard@indacoaqs.com

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#### Abstract

The University of Texas reported on a campaign to measure methane  $(CH_A)$ emissions from United States natural gas (NG) production sites as part of an improved national inventory. Unfortunately, their study appears to have systematically underestimated emissions. They used the Bacharach Hi-Flow® Sampler (BHFS) which in previous studies has been shown to exhibit sensor failures leading to underreporting of NG emissions. The data reported by the University of Texas study suggest their measurements exhibit this sensor failure, as shown by the paucity of high-emitting observations when the wellhead gas composition was less than 91% CH<sub>4</sub>, where sensor failures are most likely; during follow-up testing, the BHFS used in that study indeed exhibited sensor failure consistent with under-reporting of these high emitters. Tracer ratio measurements made by the University of Texas at a subset of sites with low CH4 content further indicate that the BHFS measurements at these sites were too low by factors of three to five. Over 98% of the CH 4 inventory calculated from their own data and 41% of their compiled national inventory may be affected by this measurement failure. Their data also indicate that this sensor failure could occur at NG compositions as high as 97% CH<sub>4</sub>, possibly affecting other BHFS measurement programs throughout the entire NG supply chain, including at transmission sites where the BHFS is used to report greenhouse gas emissions to the United States Environmental Protection Agency Greenhouse Gas Reporting Program (USEPA GHGRP, U.S. 40 CFR Part 98, Subpart W). The presence of such an obvious problem in this high profile, landmark study highlights the need for increased quality assurance in all greenhouse gas measurement programs.

#### Introduction

The climatic benefits of switching from coal to natural gas (NG) depend on the magnitude of fugitive emissions of methane ( $\mathrm{CH_4}$ ) from NG production, processing, transmission, and distribution [12, 13, 27]. This is of particular concern as the United States increasingly exploits NG from shale formations: a sudden increase in  $\mathrm{CH_4}$  emissions due to increased NG production could trigger climate "tipping points" due to the high short-term global warming potential of  $\mathrm{CH_4}$  (86× carbon dioxide on a 20-year time scale) [19]. The United States Environmental

Protection Agency (USEPA) estimates  $\mathrm{CH_4}$  emissions from the NG supply chain by scaling up individual ground-level measurements, mostly collected by reporting from industry [26]. However, some recent studies have questioned whether these "bottom-up" inventories are too low, since airborne measurements indicate that  $\mathrm{CH_4}$  emissions from NG production regions are higher than the inventories indicate [5, 14, 17, 20, 21].

In order to help determine the climate consequences of expanded NG production and use, and to address the apparent discrepancy in top-down and bottom-up measurements, the University of Texas (UT) at Austin and the

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Environmental Defense Fund launched a large campaign to measure CH4 emissions at NG production sites in the United States [1]. This study used both existing EPA GHG inventory data and new measurements to compile a new national inventory of CH<sub>4</sub> emissions from production sites. Forty-one percent of this new inventory was based on measurements made by [1], which included measurements of emissions from well completion flowbacks as well as measurements of emissions from chemical injection pumps, pneumatic devices, equipment leaks, and tanks at 150 NG production sites around the United States already in routine operation (measurements from tanks were not used for inventory purposes). However, the measurements of emissions at well production sites already in operation (which comprised 98% of the new inventory developed by [1]) were made using the Bacharach Hi-Flow Sampler (BHFS; Bacharach, Inc., New Kensington, PA) and recent work has shown that the BHFS can underreport individual emissions measurements by two orders of magnitude [10]. This anomaly occurs due to sensor transition failure that can prevent the sampler from properly measuring NG emission rates greater than ~0.4 standard cubic feet per minute (scfm; 1 scfm =  $1.70 \text{ m}^3 \text{ h}^{-1}$  or  $19.2 \text{ g min}^{-1}$  for pure CH<sub>4</sub> at 60°F [15.6°C] and 1 atm; these are the standard temperature and pressure used by the U.S. NG industry). Although this failure is not well understood, it does not seem to occur when measuring pure CH<sub>4</sub> streams, but has been observed in four different samplers when measuring NG streams with CH4 contents ranging from 66% to 95%. The sampler's firmwareversion and elapsed time since last calibration may also influence the occurrence of this problem [10, 18].

This paper presents an analysis of the UT [1] emissions measurements that were made with the BHFS, and shows that high emitters (>0.4 sofm [0.7  $\rm m^3~h^{-1}$ ]) were reported very rarely at sites with a low CH<sub>4</sub> content in the well-head gas (<91%), consistent with sensor transition failure. It also details testing of the exact BHFS instrument used in that study and shows the occurrence of this sensor failure at an NG production site with a wellhead composition of 91% CH<sub>4</sub> (the highest CH<sub>4</sub> concentration site available during testing). Finally, the downwind tracer ratio measurements made by [1] at a subset of their test sites are reexamined and indicate that the BHFS measurements made at sites with low wellhead CH<sub>4</sub> concentrations were too low by factors of three to five.

## **Evidence of BHFS Sensor Transition Failure in the UT Dataset**

The Allen et al. [1] UT dataset is unique due to the large number of BHFS measurements made across a wide geographic range, the variety of emissions sources

(equipment leaks, pneumatic devices, chemical injection pumps, and tanks) and the wide range of NG compositions (67.4–98.4%  $\mathrm{CH_4})$  that were sampled. As such, the UT study provides an important opportunity to evaluate the occurrence of sensor transition failure in the BHFS as well as the impact of this issue on emission rates and emissions factors based on measurements in other segments of the NG supply chain.

The BHFS uses a high flow rate of air and a loose enclosure to completely capture the NG-emitting from a source, with the emission rate calculated from the total flow rate of air and the resulting sample NG concentration, after the background NG concentration is subtracted. The sampler uses a catalytic oxidation sensor to measure sample concentrations from 0% to 5% NG in air, but must transition to a thermal conductivity sensor in order to accurately measure sample concentrations higher than 5%. It is the failure of the sampler to transition to the higher range that has been previously observed by Howard et al. [10] and which can prevent the sampler from correctly measuring emission rates larger than 0.3–0.5 scfm (0.5–0.9 m³ h<sup>-1</sup>) (corresponding to sampler flow rates of 6–10 scfm [10–17 m³ h<sup>-1</sup>]). Figure 1 summarizes data

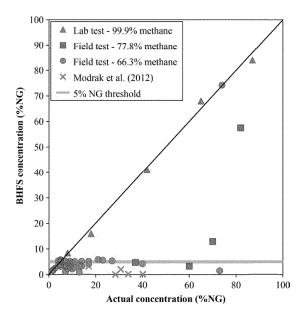


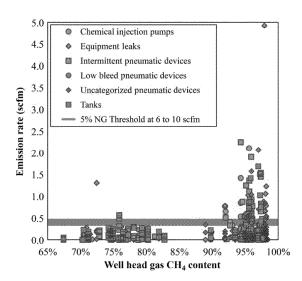
Figure 1. Occurrence of sensor transition failure in BHFS instruments with natural gas of varying CH $_4$  content from field and lab testing and from emission measurement studies (data from [10, 18]). NG concentrations in the BHFS sampling system measured by the BHFS internal sensor are compared to independent measurements of the sample NG concentrations. The 5 % NG sample concentration threshold is the approximate concentration above which sensors should transition from catalytic oxidation to thermal conductivity. BHFS, Bacharach Hi-Flow Sampler; NG, natural gas.

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showing the occurrence of sensor transition failure in several BHFS instruments during both fieldand laboratory testing as well as an example of the failure that occurred during an emission measurement study [10, 18].

Figure 2 presents the BHFS emission measurements from [1] as a function of percent  $CH_4$  in wellhead gas at each site. Figure 2 also shows a line corresponding to emission rates of 0.3–0.5 scfm (0.5–0.9  $\rm m^3~h^{-1}$ ), which represents the range of emission rates that would require transition from the catalytic oxidation sensor to the thermal conductivity sensor at sample flows ranging from 6 to 10 scfm (10–17  $\rm m^3~h^{-1}$ ).

As seen in Figure 2, there are very few measurements in the thermal conductivity sensor range (above  $\sim 0.4$  scfm  $[0.7 \text{ m}^3 \text{ h}^{-1}]$ ) at sites where the wellhead gas composition of CH<sub>4</sub> is less than 91%, and this is true across all source categories. Raw data for sample flowand concentration from the BHFS were not provided in [1] supplemental information, so for this analysis, an average BHFS sample flowrate of 8 scfm (14 m  $^3$  h $^{-1}$ ) has been assumed, which is the lower of the two sampling flows specified by the Bacharach operating manual [4]. At this sample flowrate, an emission source of 0.4 scfm (0.7 m $^3$  h $^{-1}$ ) corresponds with a sample concentration of 5% NG in air, above



**Figure 2.** Emission rates of various sources measured by BHFS at NG production sites versus CH  $_4$  concentration of the wellhead gas (data from [1]). The solid line indicates the maximum emission rate that could be measured by the catalytic oxidation sensor only (i.e., in the case of sensor transition failure). For sites with a NG composition greater than 91% CH $_4$ , 13.3% of the measurements are in the TCD sensor range, assuming a sampler flow rate of 8 cubic feet per minute. For sites with less than 91% CH $_4$ , only 1.5% of the measurements are in the TCD range. BHFS, Bacharach HiFlow Sampler; NG, natural gas; TCD, thermal conductivity detector.

which point the sampler would need to transition to the thermal conductivity sensor to allow for accurate measurements. For sites with CH<sub>4</sub> concentrations less than 91%, only four out of 259 measurements (1.5%) exceeded 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>), while for sites with CH<sub>4</sub> concentrations greater than 91%, 68 out of 510 measurements (13.3%) exceeded 0.4 scfm  $(0.7 \text{ m}^3 \text{ h}^{-1})$ . Consequently, there were almost nine times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH $_4$  (Fig. 2). If the sample flow rate were 6 scfm (10 m $^3$  h $^{-1}$ ) (due to a flow restriction or reduced battery power), the threshold for transition to the thermal conductivity range would be 0.3 scfm (0.5 m<sup>3</sup> h<sup>-1</sup>); this would still mean that there were almost seven times fewer measurements in the thermal conductivity range at sites with wellhead gas compositions of <91% CH<sub>4</sub> than at sites with >91% CH<sub>4</sub>. Although it is well known that a small percentage of NG emission sources account for most of the total emissions from any given population [9, 15, 25], it is unlikely that almost all the significant emitters at NG production sites would occur only at sites with well head gas compositions >91% CH, It is also unlikely that the emission rates of all of the source categories surveyed by [1], which had diverse emission mechanisms such as equipment leaks, pneumatic controllers, chemical injection pumps, and tanks, would all have a ceiling of ~0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) at sites with lower wellhead gas CH₄ concentrations. Consequently, the low occurrence of high emitters at sites with lower wellhead gas CH<sub>4</sub> concentrations in [1] indicates that sensor transition failure occurred at sites with CH<sub>4</sub> content <91% and is consistent with the BHFS sensor failure found by Howard et al. [10].

## Alternative Theories for the Emission Rate Pattern

Other possible causes of the emission rate pattern in the UT BHFS measurements were considered, including: regional operating differences at production sites; lighter gas densities resulting in higher emission rates; and improved detection of emissions by auditory, visual, and olfactory (AVO, e.g., [24]) methods at sites with heavier hydrocarbon concentrations.

#### Regional operating differences

Allen et al. [1] point out that air pollution regulations in Colorado which required installation of low bleed pneumatic devices in ozone nonattainment areas after 2009 might have led to lower emission rates in the Rocky Mountain region, which also had the lowest average concentration of  ${\rm CH_4}$  in the wellhead gas. However, if the

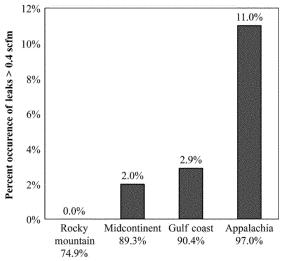
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Rocky Mountain region is removed from the analysis, the occurrence of emitters >0.4 scfm (0.7 m³ h $^{-1}$ ) at sites with wellhead gas <91% CH $_4$  was still only four out of 129 measurements (3.1%), while for sites with CH $_4$  concentrations greater than 91%, there remain 68 out of 510 measurements (13.3%) that exceeded 0.4 scfm (0.7 m³ h $^{-1}$ ) (there were no Rocky Mountain sites with CH $_4$  >91%). Consequently, even if the Rocky Mountain region is removed from consideration, the occurrence of emitters >0.4 scfm (0.7 m³ h $^{-1}$ ) was almost four times less at sites with less than 91% CH $_4$  than at sites with greater than 91% CH $_4$ , so air quality regulations in Colorado do not appear to be the cause of the emission rate trend shown in Figure 2.

Beyond air pollution regulations, other unknown regional operating practices unrelated to  ${\rm CH_4}$  concentration might coincidentally cause the apparent relationship of site  ${\rm CH_4}$  concentrations with the occurrence of high emitters. However, as shown in Figure 3, the increase in leaks >0.4 scfm  $(0.7~{\rm m^3~h^{-1}})$  directly correlates with the increase in the average regional  ${\rm CH_4}$  concentration. Because there are four regions and two variables (site  ${\rm CH_4}$  concentration and the percent of leaks >0.4 scfm  $[0.7~{\rm m^3~h^{-1}}]$ ), the likelihood that regional operating characteristics would coincidentally cause the increase in occurrence of leaks >0.4 scfm  $(0.7~{\rm m^3~h^{-1}})$  to mirror the increasing regional site  ${\rm CH_4}$  concentration is only one in 24 (four factorial), or ~4%.



Region and average wellhead CH4 concentration

**Figure 3.** Occurrence of equipment leaks >0.4 scfm in each region of the [1] equipment leak data set. The odds of the occurrence of leaks >0.4 scfm being positively correlated with site CH <sub>4</sub> concentration are one in 24, which makes it unlikely this trend is due to regional operating effects.

Other known operating characteristics of the regions, such as average site pressure and average site age, are not related to the occurrence of equipment leaks >0.4 scfm (0.7 m $^3$  h $^{-1}$ ): average site pressures show no correlation, and average site age is negatively correlated with the occurrence of equipment leaks >0.4 scfm (0.7 m $^3$  h $^{-1}$ ).

Another argument against regional differences comes from the air quality study conducted by the City of Fort Worth ([6]; or the Ft. Worth study). Ft. Worth is part of the Mid-Continent region defined by [1], where the occurrence of equipment leaks only (as opposed to all BHFS measurement categories) >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) observed by [1] was 2.0% of the total equipment leaks in that region. However, equipment leaks >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) were 9.9% of the equipment leaks measured in the Ft. Worth study. This was determined using the Ft. Worth study categories of valves and connectors; their remaining category of "other", which included pneumatic control devices, had an even higher occurrence of sources >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) of 27.0%. Previous work [10] has shown that although sensor transition failure likely occurred in the Ft. Worth study, these incidents were limited compared to those in [1]. Consequently, the much lower occurrence of leaks >0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) in the Mid-Continent region in [1] compared to the Ft. Worth study indicates that sensor transition failure was responsible for the low occurrence of emitters < 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) as opposed to regional differences.

#### Gas density

Wellhead gas with a lower  $\mathrm{CH_4}$  and a greater heavier hydrocarbon content will be denser than gas with higher  $\mathrm{CH_4}$  content. Since gas flow through an opening is inversely related to the square root of the gas density, streams with lower  $\mathrm{CH_4}$  content would have a lower flow rate if all other conditions were the same. However, this would cause at most a 20% decrease for the lowest  $\mathrm{CH_4}$ /highest heavier hydrocarbon streams compared to the highest  $\mathrm{CH_4}$ /lowest heavier hydrocarbon streams observed in the UT study. This would also result in a gradual increase in emissions as  $\mathrm{CH_4}$  content increased, as opposed to the dramatic increase in emissions observed over a very narrow range of  $\mathrm{CH_4}$  concentrations (Fig. 2).

#### **AVO** detection

AVO methods might improve for gas streams with a greater proportion of heavier hydrocarbons, since those streams would have greater odor and might leave more visible residue near a leak. However, Figure 4 presents the occurrence of emitters >0.4 scfm (0.7 m $^3$  h $^{-1}$ ) as a function of site CH $_4$  concentrations in the Appalachia

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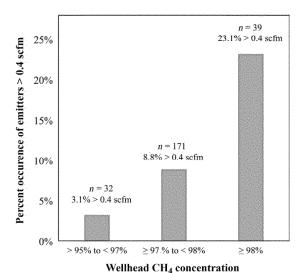


Figure 4. Occurrence of emitters >0.4 scfm as a function of site wellhead gas composition in [1] for the Appalachia region. An emission rate of greater than 0.4scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of 8scfm. The dramatic increase in emitters >0.4scfm over a narrow concentration range argues against the possibility that auditory, visual, and olfactory leak detection is the cause of the emission rate pattern seen in the [1] data set.

region alone. This region had the highest average CH<sub>4</sub> concentration in wellhead gas of any of the regions sampled in [1]. As seen in Figure 4, even over a very narrow range of site  $CH_4$  concentrations (from 95% to >98%  $CH_{A}$ ), there is a dramatic increase in emitters >0.4 scfm  $(0.7 \text{ m}^3 \text{ h}^{-1})$  with increasing CH<sub>4</sub> concentration. It is unlikely that AVO methods would become so much more efficient over such a narrow range of high CH 4 concentrations where the gas streams are likely odorless and would leave little residue. This dramatic increase in high emitters at sites with high CH<sub>4</sub> concentrations within the Appalachia region alone also argues against the previously discussed regional operating differences hypothesis in general, since this trend is within a single region. Additionally, although the Rocky Mountain region surveyed by UT [1] had the lowest average site CH<sub>4</sub> concentration (74.9%) and heaviest hydrocarbon content, it actually had the highest number of equipment leaks (of any size) per well of all the regions, and there were 25% more leaks per well in that region than in the Appalachia region, which had the highest average site CH<sub>4</sub> concentration (97.0%) and therefore the lowest heavier hydrocarbon content. If AVO methods were more effective due to the presence of heavier hydrocarbons, it seems unlikely the region with the heaviest hydrocarbon concentrations would have the highest rate of overall leak occurrences.

#### Field Testing of the UT BHFS

Because the trend in the [1] data was consistent with sensor transition failure in the BHFS and no other explanation seemed plausible, I partnered with UT to test the sampler used by [1]. During that field program, the UT sampler had a version of firmware earlier than version 3.03, and older firmware versions have been shown to exhibit sensor transition failure [10]. However, the possible effect of the sampler's firmware version on the sensor failure was not known before this testing of the UT sampler, and at the time of my testing its firmware had been upgraded to a custom version (3.04).

As previously explained, the BHFS uses a catalytic oxidation sensor to measure sample stream concentrations from 0% to  $\sim\!5\%$  NG, and a thermal conductivity sensor for concentrations from  $\sim\!5\%$  to 100% NG. The catalytic oxidation sensor is typically calibrated with 2.5% CH $_4$  in air and the thermal conductivity sensor is calibrated with 100% CH $_4$  [4]. The manufacturer recommends sensor calibration every 30 days, a process which adjusts the response of the instrument. The calibration may also be checked ("bump-tested") periodically by the user, which does not adjust the instrument response. It is important to note that the description of the BHFS sensor operation in the supplemental information of [1] is incorrect, as they state that:

[A] portion of the sample is drawn from the manifold and directed to a combustibles sensor that measures the sample's methane concentration in the range of 0.05–100% gas by volume. The combustibles sensor consists of a catalytic oxidizer, designed to convert all sampled hydrocarbons to  $\rm CO_2$  and water. A thermal conductivity sensor is then used to determine  $\rm CO_2$  concentration.

However, the BHFS manual [4] clearly states that the catalytic oxidation sensor is used to measure concentrations from 0% to 5%  $\rm CH_4$  and the thermal conductivity sensor from 5% to 100%  $\rm CH_4$ . This is a critical distinction because understanding that the BHFS uses a different sensor for each range and that it must transition from the catalytic oxidation sensor to the thermal conductivity sensor in order to conduct accurate measurements is critical to understanding the problem of sensor transition failure.

I initially conducted field testing of the UT sampler in conjunction with the UT team at a NG production site with a wellhead gas CH<sub>4</sub> concentration of 90.8%. NG composition analysis (via gas chromatograph-flameionization detector) of wellhead gas at this site was conducted by the host company just prior to the sampler testing. The tests were conducted by metering known flow rates of NG into the BHFS inlets through a rotameter (King Instrument Company, Garden Grove, CA; 0–10 scfm air

scale). The sample concentration indicated by the internal BHFS sensor was recorded and compared to an external gas concentration monitor used to measure the actual NG concentration at the sampler exhaust (Bascom-Turner Gas Sentry CGA 201, Norwood, MA). The Gas Sentry unit was calibrated with 2.5% and 100%  ${\rm CH_4}$  prior to the testing; exhaust concentrations measured using this unit agreed with concentrations calculated using the sampler flow rate and amount of NG metered into the inlet to within an average of  $\pm 6\%$ .

This field testing was conducted in March of 2014 and is described by [10]; the UT sampler is identified therein as BHFS No. 3. At the time of this testing, the UT BHFS had firmwareVersion 3.04 (September 2013); this sampler had been calibrated 2 weeks prior to the fieldtest and had been used for emission measurements at production sites since that time. The response of the sensors was checked ("bump-tested") by the UT field team but not calibrated prior to the start of testing. This was apparently consistent with the UT fieldprogram methodology: the sampler had been used for measurements with only sensor bump tests, but without the actual calibration unless the sensors failed the bump tests (as was acceptable according to the manufacturer's guidelines) during their ongoing field measurement program and was provided to me for these measurements "ready for testing".

Although the UT sampler's internal sensors initially measured the sample concentration correctly, after ~20 min of testing the sampler's sensors failed to transition from the catalytic oxidation scale (<5% NG) to the thermal conductivity scale (>5% NG), resulting in sample concentration measurements that were 11-57 times lower than the actual sample concentration (Fig. 5). Because sample concentration is directly used to calculate emission measurements made by the sampler, this would result in emission measurements that are too low. After this sensor transition failure occurred, the UT BHFS was calibrated (not simply "bump-tested") and thereafter did not exhibit any further sensor transition failures even during a second day of testing at sites with wellhead CH<sub>4</sub> concentrations as low as 77%. Two other BHFS that were not part of the UT program were also tested using the same procedure: these instruments had the most updated firmware commercially available (Version 3.03) and were put through an actual calibration sequence by the instrument distributor's representative prior to any testing. Neither of these instruments exhibited sensor transition failure at any of the sites. These results combined with the sensor transition failure previously observed in instruments with earlier versions of firmware suggest that the combination of updated firmware and frequent actual calibrations might reduce sensor failure, although this has not been proved conclusively [10, 11].

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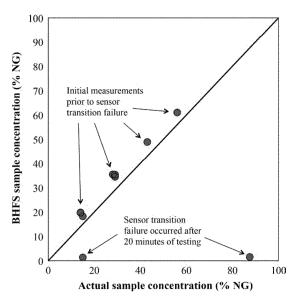


Figure 5. Performance of the BHFS used during the [1] study with NG composed of 90.8% CH<sub>4</sub>; instrument firmware had been upgraded to version 3.04 after that study but before this testing; calibration was 2 weeks old. Sensor transition failure set in after ~20min of testing; this failure was eliminated once the BHFS was put through a calibration sequence (as opposed to just a response test). BHFS, Bacharach HiFlow Sampler: NG, natural gas.

The UT recently published a follow-up study of pneumatic device emissions [2]. As part of this work, Allen et al. [2] conducted laboratory testing of the UT BHFS by making controlled releases of both 100% CH<sub>4</sub> and a test gas of 70.5% CH<sub>4</sub> mixed with heavier hydrocarbons into the UT BHFS and did not report any sensor transition failures during these tests, but during this laboratory testing the sampler (with the updated firmware version 3.04) was calibrated (not 'bump-tested") immediately prior to any testing. Consequently, the absence of sensor failure during their laboratory testing is consistent with the results observed during the March 2014 field tests, where calibrating the instrument eliminated the sensor failure.

Allen et al. [3] have suggested that the protocol during their field campaign was to check the calibration of the UT BHFS anytime it was turned on and that not following this protocol led to the sensor transition failure observed during this testing. However, in this instance, the sensor failure occurred both prior to and after the instrument was restarted. Additionally, the UT team observing the testing process did not suggest a calibration check when the instrument was turned back on for further testing. It was only after the sensor failure was observed that they checked and calibrated the instrument, so it

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does not appear that their protocol was to check the instrument calibration anytime it was turned on.

In summary, because the firmwarefor the UT sampler was updated prior to this testing (and therefore not the same as the version used during the UT field campaign [1]), and updated firmware may be a factor in reducing sensor failure, it is not expected that these test results are representative of how frequently sensor transition failure might have occurred during the UT study [1]. However, these results do clearly demonstrate that sensor transition failure could occur while using the UT BHFS.

### Comparison With Other Pneumatic Device Studies

Two other recent studies have measured emission rates from pneumatic devices by installing meters into the supply gas lines of the devices, as opposed to measuring emissions using the BHFS as was done by Allen et al. [1]. Prasino [22] used the meter installation technique to study emissions from pneumatic controllers in British Columbia, and the UT follow-up study [2] installed meters to measure emission rates from pneumatics in the four regions surveyed in the previous UT study [1].

Unfortunately, it is not possible to compare the pneumatic device emission factors from [1] to those from either the Prasino study, or from [2], because even though [1] sought to randomly sample pneumatic devices, the result was clearly an emitter data set (measurements focused on pneumatic devices that were emitting), while the Prasino data set was made with a random selection of devices and [2] made comprehensive measurements of all devices that could be measured safely at each site. This difference can be demonstrated by comparing the percentage of emitting intermittent pneumatic devices occurring in [1] to that in [2]. In [1], 95.3% (123 out of 129 intermittent devices) were greater than zero, with the smallest nonzero emitter equal to 0.12 scfh  $(0.0034 \text{ m}^3 \text{ h}^{-1})$ . In [2], only 57.5% (184 out of 320) intermittent devices) were greater than zero. This percentage of nonzero measurements drops further if the lowest nonzero emitter (0.12 scfh; 0.0034 m<sup>3</sup> h<sup>-1</sup>) observed by [1] is used as a threshold, in which case only 21.3% (68 out of 320) would be considered emitters. Since this threshold of 0.12 scfh (0.0034 m<sup>3</sup> h<sup>-1</sup>) is 25 times lower than the typical minimum range of the Fox FT2A meters by [2], the reported emitters below this threshold are most likely instrument noise caused by the meter's thermal elements inducing convection currents [7].

Consequently, although the intent of [1] was to survey randomly selected devices, their approach actually resulted in a data set comprised almost exclusively of emitting devices; this possibility is acknowledged by [2]. Therefore,

average emissions and emission factors for pneumatic devices calculated from [1] cannot be compared to those calculated from data collected by random or comprehensive sampling, such as presented in [22] or [2], because the emitter data set removes almost all the zero emitters and would result in much higher average emissions.

However, both [1] and [2] provide the  $\mathrm{CH_4}$  composition of the wellhead gas at the sites surveyed. This allows a comparison of emission rate patterns as a function of  $\mathrm{CH_4}$  concentration between devices measured by the BHFS [1] and by installed meters [2]. If the scarcity of high emitters measured by BHFS at sites with lower  $\mathrm{CH_4}$  concentrations in the initial UT study [1] was not an artifact caused by sensor transition failure, then the same concentration pattern should be present whether measured by the BHFS or by installed meters.

For this analysis, I removed the Rocky Mountain region to eliminate any bias from current or impending regulations that might have affected emission rates. Additionally, I focused on emissions from intermittent pneumatics because that provides the most complete data set from the two studies. Finally, as noted previously, the pneumatic device measurements from [1] apparently focused on emitting devices, whereas the devices surveyed in [2] were sampled as comprehensively as possible so the occurrences of high emitters in each study cannot be directly compared. Consequently, it is the ratio of the occurrences of high emitters at low CH<sub>4</sub> sites compared to high CH<sub>4</sub> sites within each study that must be compared.

As seen in Table 1, when measured by [1] via BHFS, the occurrence of emitters >0.4 scfm (0.7 m $^3$  h $^{-1}$ ) (on a percentage basis) at sites with wellhead gas compositions <91% CH $_4$  is almost a factor of five less than at sites with CH $_4$  >91%, consistent with BHFS sensor failure. Conversely, when measured via installed meters [2], the occurrence of emitters >0.4 scfm (0.7 m $^3$  h $^{-1}$ ) at sites with wellhead gas compositions <91% CH $_4$  is almost a factor of three higher than at sites with >91% CH $_4$ , indicating a complete reversal in this trend. This stark difference between BHFS measurements and installed meter measurements corroborates that the scarcity of high emitters at sites with lower wellhead gas CH $_4$  content present in [1] was an artifact due to sensor failure in the BHFS.

## Focused Analysis of the UT Study Equipment Leaks

In order to better understand the threshold of wellhead gas CH<sub>4</sub> concentrations at which sensor transition failure might occur, I conducted further analysis focused only on the equipment leak measurements in [1]. Equipment leaks were targeted because they are expected to be short term, steady state measurements, whereas emissions

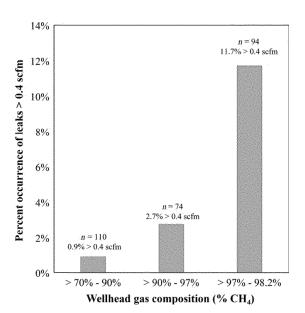
UT Study Underestimates Methane Emissions

Table 1. Occurrence of intermittent pneumatic device high emitters as a function of wellhead gas composition, measured by Bacharach Hi- Flow Sampler (BHFS) and installed meters (Rocky Mountain region excluded).

	No. of devices measured	No. of devices with emissions >0.4 scfm	% of devices with emissions >0.4 scfm
Allen et al. [1] (Measured by BHFS sampler)			
Wellhead gas composition >91% CH₄	85	28	32.9
Wellhead gas composition <91% CH <sub>a</sub>	44	3	6.8
Ratio of frequency of high emitters at sites with well wellhead gas compositions >91% CH <sub>4</sub>	nead gas compositions <91% CF	નું to sites with	0.21
Allen et al. [2] (Measured by installed meters)			
Wellhead gas composition >91% CH₄	106	3	2.8
Wellhead gas composition <91% CH	97	8	8.2
Ratio of frequency of high emitters at sites with well wellhead gas compositions >91% CH <sub>4</sub>	nead gas compositions <91% Ch	ન્ <sub>ય</sub> to sites with	2.9

reported from pneumatic devices and chemical injection pumps are likely to be an average of several measurements, and emissions from tanks may have an NG composition different from the reported wellhead composition.

Figure 6 presents the occurrence of equipment leaks in [1] that are >0.4 scfm (0.7 m³ h $^{-1}$ ) as a function of site CH $_4$  concentrations. At sites with gas compositions of >97% CH $_4$ , 11.7% of the leaks were >0.4 scfm (0.7 m³ h $^{-1}$ ). At sites with wellhead compositions between 90% and 97% CH $_4$ , only 2.7% of the leaks were >0.4 scfm



**Figure 6.** Occurrence of equipment leaks >0.4scfm as a function of site well head gas CH <sub>4</sub> content in the [1] study. Leaks >0.4 scfm would require the transition from catalytic oxidation sensor to the thermal conductivity sensor for an average sample flow rate of &scfm. The large increase in the occurrence of leaks >0.4 scfm at sites with CH<sub>4</sub> content >97% indicates sensor transition failure below that threshold.

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(0.7 m³ h⁻¹), and this occurrence dropped to less than 1% at sites with wellhead gas compositions of <90% CH₄, indicating that the sampler's ability to measure leaks >0.4 scfm (0.7 m³ h⁻¹) declined dramatically with decreasing concentrations of CH₄ in the wellhead gas (Fig. 6). This analysis indicates the BHFS may underreport emitters >0.4 scfm (0.7 m³ h⁻¹) even when making measurements of NG streams with CH₄ content up to 97%, and provides a valuable refinement of the possible CH  $_4$  concentration threshold where sensor failure may occur, since the highest CH₄ wellhead content available for direct field testing of the BHFS was only 91.8%.

#### Comparison of the UT Study Downwind Tracer Ratio Measurements to On-Site Measurements

Allen et al. [1] also made emission measurements using a downwind tracer ratio method at 19 sites for comparison to their on-site measurements. Their emissions from onsite measurements were calculated by using direct measurements of equipment leaks and pneumatic devices that were made by the UT team combined with estimates of emissions from any sources at the well pad that were not measured. These unmeasured sources included all tanks and compressors (compressors were a small source in comparison to all other sources) as well as any pneumatics that was not directly measured during the site survey. For CH<sub>4</sub> emissions from tanks and compressors, the authors used "standard emissions estimation methods" [1]. For pneumatic devices that were not surveyed, they applied their own emission factors based on the measurements of pneumatic devices collected during the UT study.

The tracer ratio measurements were made by releasing a tracer gas at a known rate to simulate the emissions from the site being measured. Simultaneous downwind measurements were then made of the concentrations of both the tracer gas and  $CH_4$ , and then the emission rate

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of  ${\rm CH_4}$  was calculated after correcting for background  ${\rm CH_4}$  and tracer concentrations. The tracer ratio method allows for the calculation of  ${\rm CH_4}$  emissions from the entire production site by accounting for the dilution of  ${\rm CH_4}$  as it is transported into the atmosphere from the source to the receptor.

In summarizing their tracer ratio measurements, [1] state: "For the production sites, emissions estimated based on the downwind measurements were also comparable to total on-site measurements; however, because the total on-site emissions were determined by using a combination of measurements and estimation methods, it is difficult to use downwind measurements to confirm the direct source measurements." However, upon further examination, I found that the downwind tracer measurements do in fact indicate the occurrence of sensor transition failure in their BHFS measurements.

Table 2 summarizes the characteristics of the sites surveyed by [1] using both the BHFS and the tracer ratio method. As described above, the on-site total is a combination of the measurements made by BHFS and estimates for any sources not actually measured by the UT team. I calculated the ratio of actual BHFS measurements to

the total reported on-site emissions (estimated and measured) using the supplemental information provided by [1]. Actual measured emissions ranged from 1% to 79% of the total reported on-site emissions and the on-site total emissions range from 13% to 3500% of the downwind tracer ratio measurements (Table 2).

Table 3 compares the tracer ratio measurements to the on-site emissions, categorized by  ${\rm CH_4}$  content in the well-head gas and by the fraction of actual BHFS measurements that comprise the on-site emissions. As shown in Table 3, when comparing all sites without separating them into these categories, the total of the tracer ratio measurements does agree closely to the on-site emissions, as [1] concluded. However, four of the sites had wellhead gas compositions of  $\geq 97\%$   ${\rm CH_4}$ , at which the BHFS would be expected to make accurate measurements. The remaining 15 sites had wellhead gas compositions of < 82%  ${\rm CH_4}$ , at which sensor transition failure might occur and the BHFS would underreport emissions measurements.

Once the sites are categorized by these wellhead gas compositions, a deficit between the on-site emissions and the tracer ratio measurements appears in sites with lower  $CH_A$  concentrations, and this deficit becomes more

Table 2. Sites surveyed by Allen et al. [1] using both Bacharach Hi-Flow Sampler (BHFS) and downwind tracer methods.

Tracer site name <sup>1</sup>	BHFS site name <sup>1</sup>	Wellhead gas CH <sub>4</sub> concentration (%)	On-site total <sup>2</sup> (BHFS measurements and estimates) (scfm CH <sub>4</sub> )	BHFS measure- ments/on-site total <sup>3</sup>	Leaks measured by BHFS/on-site total <sup>3</sup>	Tracer ratio emission rate (scfm CH <sub>4</sub> )	On-site total/ tracer ratio emission rate
MC-1	MC-1	70.9	1.89	0.12	0.12	2.32	0.815
MC-2	MC-14	78.1	0.99	0.34	0.01	2.00	0.495
MC-3	MC-20	77.2	1.63	0.45	0.18	2.95	0.552
MC-4	MC-5	74.2	2.31	0.19	0.14	3.36	0.687
MC-5	MC-16	79.3	1.85	0.56	0.18	4.16	0.445
RM-1	RM-7	81.9	0.22	0.11	0.09	0.584	0.368
RM-2	RM-8	74.5	4.43	0.02	0.02	1.70	2.60
RM-3	RM-1	76.4	0.13	0.67	0.69	0.442	0.303
RM-4	RM-3	74.9	0.11	0.21	0.00	0.839	0.137
RM-5	RM-2	74.5	0.09	0.35	0.33	0.240	0.392
RM-6	RM-5	74.5	0.74	0.41	0.42	0.421	1.75
RM-7	RM-14	74.5	0.27	0.26	0.26	0.368	0.736
RM-8	RM-19	76.2	0.29	0.82	0.79	1.08	0.266
RM-9	RM-12	74.5	0.38	0.05	0.05	0.864	0.436
RM-10	RM-4	76.2	2.86	0.01	0.00	0.080	35.7
AP-2	AP-23	97.6	1.28	0.68	0.35	0.270	4.74
AP-3	AP-43	97.0	4.75	0.62	0.59	4.12	1.15
AP-4	AP-37	97.0	1.36	0.44	0.42	0.709	1.92
AP-5	AP-18	97.0	0.39	0.74	0.69	0.288	1.37

<sup>&</sup>lt;sup>1</sup>MC, Midcontinent; RM, Rocky Mountain; AP, Appalachia. Different site numbers were used to identify the same sites in the [1] supplemental information depending on whether BHFS or tracer ratio measurements were under discussion.

<sup>&</sup>lt;sup>2</sup>On-site totals were calculated by [1] by combining measurements made by the BHFS with estimates of any sources not measured; these estimates were made using mathematical models for tanks as well as emission factors for compressors and any pneumatic controllers not directly measured. 
<sup>3</sup>Calculated by this author from [1] supplemental information.

pronounced as the amount of the on-site emissions actually measured by the BHFS becomes a larger fraction of the total on-site emissions (measured and estimated). As seen in Table 3, for the high CH<sub>4</sub> sites where the sampler should function properly, the on-site measurements and estimates exceed the tracer measurements, but approach a ratio of one (complete agreement) as the amount of actual measurements increases. For the two sites with wellhead gas compositions ≥97% where the measured equipment leaks (which should produce steady emissions as compared to pneumatic devices which might be intermittent) averaged 64% of the total on-site measurements and estimates, the on-site total still exceeds the tracer measurements but are within 17% (Table 3). However, for the sites with wellhead gas  ${\rm CH_4}$  concentrations <82%, there is a clear trend of increasing deficit of the on-site emissions compared to the tracer ratio measurements as the actual BHFS measurements become a larger part of the on-site total. For instance, for the nine sites with at least 20% of on-site emissions from BHFS measurements (for an average of 45% of the total on-site emissions measured by the BHFS), the on-site emissions are only 49% of the tracer measurements (Table 3). For the two sites that had greater than 67% of on-site emissions data actually measured by the BHFS (for an average of 75% of on-site emissions data measured by the BHFS), the on-site emissions are only 28% of the tracer measurements (Table 3).

Comparing the on-site data to the downwind tracer measurements provides two valuable insights. First, there were six sites in the Rocky Mountain region for which at least 20% of the on-site emissions were measured by the BHFS (for an average of 45% actual BHFS measurements) (Table 2). For these six sites, the on-site emissions average 48% of the tracer data. For the two sites in this

region with at least 67% of on-site emissions from actual BHFS measurements (and with BHFS measurements averaging 75% of the total on-site data), the on-site emissions were only 28% of the tracer measurements (Table 2). This provides clear evidence that the sampler actually did fail in the Rocky Mountain region, as opposed to any possible regional differences (discussed previously) that might have created an emission pattern of no high emitters at sites with lower  ${\rm CH_4}$  concentrations in the wellhead das.

Additionally, the tracer measurements provide a method to estimate the magnitude of errors introduced in the data collected by [1] due to BHFS sensor transition failure. For all of the sites with wellhead gas compositions ≥97% CH<sub>4</sub> (where the sampler should operate correctly), the emission rates determined by on-site measurements exceeded those determined by the downwind tracer ratio measurements. Assuming that the tracer method accurately measured the total emissions from the sites surveyed (e.g., [8, 15, 16]), I concluded that the methods used in [1] overestimated the on-site sources that were not directly measured. Therefore, I calculated the error in BHFS measurements at sites with low CH<sub>4</sub> wellhead gas composition by assuming the tracer ratio measurements are correct. I have also assumed for this analysis that the estimates of any onsite sources made by [1] are also correct, even though the tracer data indicate they may be too high, because this is conservative in the sense that correcting for this overestimate would increase the BHFS error calculated below. Given these assumptions, subtracting the on-site estimated emissions from the tracer ratio emissions gives the expected measurement total that should have been reported from the BHFS measurements. Comparing this expected measurement total to the actual

Table 3. Comparison of on-site measurements to tracer ratio measurements made by Allen et al. [1] categorized by wellhead gas CH<sub>4</sub> concentration.

Site category (number of sites in parentheses)	Average percentage of on-site emissions reported by BHFS	Total on-site emissions (reported by BHFS and estimated) (scfm CH <sub>4</sub> )	Total emissions measured by tracer (scfm CH <sub>4</sub> )	Ratio of on-site emissions to emissions measured by tracer
All sites (19)	37	26.0	26.8	0.97
Sites where BHFS measurements are expected	to be accurate (wellhead	Igas composition ≥97% Ch	<u>k</u> )	
All sites (4)	62	7.78	5.39	1.44
Sites with >50% BHFS measurements (3)	68	6.42	4.68	1.37
Sites with >50% equipment leaks (2)	64 (equipment leaks/on-site total)	5.14	4.41	1.17
Sites where BHFS measurements are expected	to underreport high emi	tters (wellhead gas compos	tion <82% CH <sub>4</sub> )	
All sites (15)	28	18.2	21.4	0.85
Sites with ≥5% BHFS measurements (13)	35	10.9	19.6	0.56
Sites with ≥20% BHFS measurements (9)	45	6.10	12.5	0.49
Sites with >50 % BHFS measurements (3)	69	2.27	5.68	0.40
Sites with >67 % BHFS measurements (2)	75	0.42	1.52	0.28

BHFS, Bacharach Hi-Flow Sampler.

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measurement total reported by the BHFS provides an estimate of the error in BHFS measurements made by Allen et al. [1].

Table 4 presents the results of this analysis, and shows that for the 13 sites with wellhead gas compositions <82% CH<sub>4</sub> and with at least 5% actual BHFS measurements (with an average of 35% of emission sources measured by BHFS; bottom half of Table 3), the actual measurement total of the BHFS is less than one-third of the expected total, and this appears consistent as sites with greater fractions of actual BHFS measurements are examined. For these sites, the emission rates for equipment leaks and pneumatics devices presented by [1] are approximately equal, so it is not possible to assign a larger error to one category or another. Additionally, the errors introduced by the sensor failure would be expected to vary from site to site depending on how many emitters were present with emission rates exceeding the sensor transition threshold ceiling. Nevertheless, for these 13 sites, the BHFS underreported emissions for equipment leaks and pneumatic devices on average by more than a factor of 3 (Table 4).

Although the magnitude of error due to BHFS sensor failure is not known for all the sites in [1], the tracer ratio measurements make clear that the BHFS measurements for sites with lower CH<sub>4</sub> content in the wellhead gas could be at least a factor of three too low. More precise estimates of errors in [1] are not possible because of the nature of the sensor failure. Unlike a simple calibration error, for which it might be possible to correct, when sensor transition failure occurs, it is not possible to know for any particular measurement if the failure has occurred, and if it has, what the resulting error was, since the reported emission rates could range from 20% to two orders of magnitude too low.

#### **Implications**

Sensor transition failure is clearly apparent in the BHFS measurements made in the UT study by Allen et al. [1], as evidenced by the rare occurrence of high emitters at sites with lower CH<sub>4</sub> (<91%) content in the wellhead gas. The occurrence of this sensor transition failure was corroborated by fieldtests of the UT BHFS during which it exhibited this sensor failure, as well as by tracer ratio measurements made by [1] at a subset of sites with lower wellhead gas CH4 concentrations. At this subset of sites, the tracer ratio measurements indicate that the BHFS measurements were too low by at least a factor of three. Because BHFS measurements were the basis of 98% of the inventory developed by [1] using their own measurements (and 41% of their total compiled inventory), the inventory clearly underestimates CH<sub>4</sub> emissions from production sites. However, the extent of this error is difficult to estimate because the underreporting of emission rates due to BHFS sensor transition failure at any given site would vary depending on sampler performance and on how many high emitters were present at that site. Estimating this error is further complicated by the fact that the data set collected for pneumatic devices by [1] was an emitter data set; this might offset the effect of underreported high emitters in their pneumatic device emission factors. Finally, although real differences may exist in regional emission rates, the UT data set [1] should not be used to characterize them because the occurrence of sensor failure clearly varied between regions due to variations in wellhead CH₄ compositions, which may mask any actual regional differences that existed.

Although the performance of the BHFS may vary between instruments or with sensor age or calibration vintage, this analysis of the [1] data set shows that measurements made using a BHFS for NG streams with  $CH_4$  content

**Table 4.** Estimation of underreporting in Allen et al. [1] BHFS measurements of CH<sub>4</sub> emission rates at sites with low CH<sub>4</sub> well head gas composition (<82%), using downwind tracer measurements (from Table 3).

Minimum percentage of on-site emissions reported by BHFS	Average percentage of on-site emissions reported by BHFS	No. of sites	Total emissions measured by tracer (scfm CH <sub>4</sub> )	On-site emissions estimated by UT (excludes BHFS measure- ments) (scfm CH <sub>4</sub> )	Expected BHFS measurement total (tracer – on-site estimates) (scfm CH <sub>4</sub> )	Emissions reported by BHFS (sofm CH <sub>4</sub> )	Ratio of reported BHFS to expected BHFS
≥5	35	13	19.63	7.09	12.54	3.81	0.30
≥20	45	9	12.50	3.34	9.16	2.76	0.30
>50	69	3	5.68	0.71	4.97	1.56	0.31
>67	75	2	1.52	0.11	1.42	0.31	0.22

BHFS, Bacharach Hi-Flow Sampler; UT, University of Texas.

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up to 97% could lead to severe underreporting of NG leaks. That this failure can occur at such high  $\mathrm{CH_4}$  concentrations, which are close to the higher end of those found in transmission and distribution systems, indicates that past measurements in all segments of the NG supply chain could have been affected by this problem. Because the BHFS sensor transition failure phenomenon is not fully understood, it is not known how much this error may have affected past measurements of  $\mathrm{CH_4}$  emission rates. Two factors preclude this: first, the performance of any individual BHFS may vary, and second, once sensor transition failure occurs, there is no way to determine the magnitude of the measurement error in the absence of an independent flux or concentration measurement.

If BHFS sensor transition failure has occurred during industry monitoring at transmission, storage, and processing compressor stations where the BHFS is approved for leak measurements mandated by the USEPA Subpart W Greenhouse Gas Reporting Program (GHGRP) [23], then these errors could be larger than those observed at production sites. Leaks at transmission, storage, and processing compressor stations commonly exceed 0.4 scfm (0.7 m<sup>3</sup> h<sup>-1</sup>) (the approximate threshold for BHFS sensor transition failure) and in some cases may range from 10 to over 100 scfm. Because the largest 10% of leaks typically account for 60-85% of the total leak rate at a given facility [9, 25], sensor transition failure in the BHFS could bias CH4 emission inventories compiled by the USEPA GHGRP substantially low since the most significant leaks could be underreported. Additionally, leak measurements using the BHFS may be used to guide repair decisions at NG facilities, and underreporting of leaks could compromise safety if large leaks remain unrepaired as a result.

Finally, it is important to note that the BHFS sensor failure in the UT study [1] went undetected in spite of the clear artifact that it created in the emission rate trend as a function of wellhead gas CH<sub>4</sub> content and even though the authors' own secondary measurements made by the downwind tracer ratio technique confirmed the BHFS sensor failure. That such an obvious problem could escape notice in this high profile, landmark study highlights the need for increased vigilance in all aspects of quality assurance for all CH<sub>4</sub> emission rate measurement programs.

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#### **Conflict of Interest**

The author is the developer of high flowsampling technology (US Patent RE37, 403) and holds a license to use it for any purpose; however, he does not sell high flow samplers nor was he involved in the development of the Bacharach Hi-Flow Sampler.

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# Response to "Comment on "University of Texas study underestimates national methane emissions inventory at natural gas production sites due to instrument sensor failure""

Journal:	ENERGY SCIENCE & ENGINEERING
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Search Terms:	Environment, Natural gas, Safety
Abstract:	The authors of the University of Texas (UT) study dispute my analysis in "University of Texas study underestimates national methane emissions inventory at natural gas production sites due to instrument sensor failure" demonstrating that sensor transition failure affected their Bacharach Hi-Flow Sampler (BHFS) measurements at natural gas production sites. Although I addressed most of their arguments in the original paper, here I summarize the relevant evidence and also provide a simplified comparison of their downwind tracer measurements and on-site measurements. This comparison provides clear independent verification, using the authors' own data, that their BHFS measurements were too low at sites with lower methane content in the wellhead gas. Because the BHFS sensor failure presents a critical safety issue, and their incorrect defense of this work distracts from this problem, I call upon the authors and sponsors of the UT study to retract the UT BHFS measurement data in order to ensure the safety of industry personnel and to protect the health of communities near oil and natural gas facilities.

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Dr. Allen and colleagues from the University of Texas (UT) (1) argue that sensor transition failure in the Bacharach Hi-Flow Sampler (BHFS) did not affect their 2013 UT study (2) as I presented in (3). This is a welcome and critically important discussion because sensor failure in the BHFS may cause both underreporting of methane (CH<sub>4</sub>) emissions and underestimation of the health effects from air emissions at oil and natural gas (NG) facilities. Most importantly, however, the BHFS is also used to prioritize the repair of NG leaks, and if a large leak were not repaired because the BHFS underestimated it, this could lead to catastrophic component failure and/or explosion.

Although the rebuttal by (1) contends that the BHFS has been used since the 1990's, the BHFS has actually only been commercially available since 2003. High flow sampling measurements of NG leaks made prior to this were done with custom built instruments based on my design, which Bacharach, Inc. then developed into the BHFS. However, I am not affiliated with Bacharach, Inc. and I was not associated with the development of the BHFS.

The primary evidence of sensor failure is not the lack of high emitters in the UT BHFS data set (2) as stated by (1) but rather the direct experimental observance of this failure, which has been reported in (4) and (5), and, as summarized in (3), has been observed in four out of six samplers that were tested using NG with CH<sub>4</sub> content of < 91%. However, because the UT BHFS data set (2) contains measurements of several different types of sources with wide ranges of natural gas compositions, it provides a unique opportunity to evaluate the possibility that the occurrence of sensor failure might be widespread. It is certainly important to recognize that the BHFS measurements in (2) were biased low by sensor failure so that this data set is not relied upon to inform public policy. However, the much more important result of my analysis (3) of the UT BHFS data set is that sensor failure could indeed be widespread, since it appears to have occurred when measuring NG streams with CH<sub>4</sub> concentrations as high as 97%. This means that BHFS measurements throughout all sectors of the NG industry could be affected.

A third point of confusion is the contention by (1) that air pollution regulations in the Rocky Mountain region resulted in lower emission rates in that region, and that this explains the lack of high emitters at sites with lower  $CH_4$  content observed in their study because that region also had a lower  $CH_4$  content in the wellhead gas. Air pollution regulations might indeed result in lower emission rates in the Rocky Mountain region, but my analysis in (3) explains in detail that this is clearly not the cause of the scarcity of high emitters at sites with wellhead gas of lower  $CH_4$  content. To summarize, my analysis explains that:

- 1) Even when the Rocky Mountain region is excluded, there are still almost four times fewer high emitters at sites with wellhead NG compositions < 91% CH<sub>4</sub> than sites with > 91% CH<sub>4</sub>;
- 2) Pneumatic device emissions measured using flowmeters in a UT follow-up study (6) show a complete reversal of the pattern of pneumatic device emissions measured by BHFS in the UT study (2), i.e., when measured by flow meters, there was a larger occurrence of high emitters at sites with low well head gas CH<sub>4</sub> content;
- 3) Emission rates measured by BHFS reported by (2) within a single region Appalachia show a dramatic pattern of decreasing occurrence of high emitters as wellhead CH<sub>4</sub> concentration decreases over a narrow range from 98 to 95% CH<sub>4</sub>; and

4) Although the downwind tracer measurements (discussed in further detail below) made by (2) confirm that emission rates in the Rocky Mountain region were lower than other regions, these measurements also confirm that the BHFS measurements are too low at sites with low wellhead gas CH<sub>4</sub> content, even in the Rocky Mountain region.

It was also asserted by (1) that both field and laboratory testing showed little evidence of the sensor failure. As described in (3), I tested the sampler used in the UT study after the publication of their initial results in (2) in the presence of members of the UT field team and observed the sensor failure during this testing (4). This failure occurred even though the sampler had been upgraded to a new generation of firmware after it was used to conduct the measurements made during the initial UT study (2). After I conducted this field testing, I immediately interviewed two experienced BHFS technicians not associated with the UT team who reported that the new generation of firmware had eliminated problems in their samplers that caused leaks too be reported too low. Given the dramatic improvement in performance of samplers reported by these technicians using the updated generation of firmware, it is not surprising that the sensor failure only occurred sporadically in the UT sampler during the field tests and was not observed in their laboratory tests. Indeed, it is rather surprising that sensor failure occurred at all in a unit with updated firmware, although this highlights that the factors affecting sensor failure are still not well understood. I immediately relayed these reports of improved performance of samplers with updated software to the UT team in March of 2013, so the authors of (1) and (2) are well aware that the performance of the UT sampler could have been much worse when it was used for the original UT study (2), during which time it had older firmware. It is also interesting to note that during the March 2013 field testing, the UT team had a second BHFS that they did not allow me to test, stating that it had too many problems to make testing it worthwhile, although the nature of those problems was not specified.

The rebuttal (1) further asserts that the reason sensor transition failure occurred in the UT sampler during the field testing I conducted was that the proper UT calibration protocol was not followed. As I explained in (3), the UT team made no effort to conduct calibrations after the instrument was turned off and on but only did so after sensor failure was noted. Consequently, in contrast to what they have stated in (1), it does not appear that the UT protocol was to calibrate any time the instrument was turned on.

Allen and his colleagues (1) also state that because the average emission rates of pneumatic devices measured by flow meters in their follow-up study (6) are lower than those measured by their BHFS in (2), this disproves the possibility of sensor failure since sensor failure should cause the BHFS measurements to be lower. However, as I explained in (3), the pneumatic device data collected by BHFS (2) were clearly not a random sample but instead focused only on emitting devices and inadvertently excluded zero emission sources. This is one reason why average pneumatic device emission rates calculated from the BHFS data (2) are higher than those calculated from the flow meter data (6). Additionally, much of the pneumatic device data collected by flow meters (6) was likely biased low due to calibration problems. The authors of (6) only calibrated their meters before and after their field work, and claim in their supplemental information that they only became aware of a calibration problem with one meter during their post project calibration. However, as I reported in (7), I also tested the UT flow meters in March of 2013 while the measurements for the follow-up study (6) were ongoing, again in the presence of the UT field team. During these tests, one of their two primary meters indicated flow rates that were a factor of three lower than the actual flow rates released through the meters. Even

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after applying their post project calibration correction (6), the flow rates measured by this faulty meter during these tests would still be a factor of two lower than the actual flow rates. These two additional failures of quality assurance – the inadvertent exclusion of zero emitters from a supposedly random sample of devices in (2) and the inadequate calibration of flow meters in (6) – further highlight the need for dramatic improvements in greenhouse gas measurements programs.

Allen and colleagues (1) also maintain that infrared camera data showed no evidence that the BHFS did not accurately measure high emitters; however, there is ample evidence that infrared camera visualization cannot be currently used to quantify leaks. For instance, during the Ft. Worth Air Quality study (8), daily QA checks on the IR camera indicated variations in factors of up to 15 in the distance at which a known leak could be identified, much less quantified, under calm conditions. This large variability, even under calm conditions, demonstrates the huge uncertainty in trying to quantify emission rates with an IR camera, since any air movement near the leak would dramatically increase this variability.

Finally, their rebuttal (1) also states that my comparison (3) of the downwind tracer measurements to the on-site emissions measurements in the UT study (2) is "complex" and obscures the fact that the average emission rates from wells in the Rocky Mountain region were too small for the sensor failure to have occurred. In particular, they state: "The average per well emissions in the Rocky Mountains, made using independent downwind sampling at sites with 40 wells, were low. The average emission rates from these wells were less than half of the emissions that would be expected from just one high emission rate source per well that Howard (2015) argues should be prevalent at sites with high methane concentrations. Simply stated, if there were missing emissions of the magnitude asserted by Howard (2015), they would have significantly increased measured downwind concentrations."

However, this claim by (1) ignores the fact that the downwind tracer technique was used to measure  $CH_4$  emissions not from individual wells but from sites with an average of almost five wells per site, so the emission rates per site are much higher than the emission rates per well. In fact, the average emission rate per site measured by downwind tracer in the Rocky Mountain region was 0.66 scfm, over 50% greater than the expected BHFS sensor transition threshold of 0.4 scfm at a sample flow of 8 scfm. If the BHFS sample flow were reduced to 4 scfm due to low battery power or a tightly wrapped enclosure, then sensor transition failure could occur when measuring a source as small as 0.2 scfm. Consequently, a single measurement of a high emitter at these sites that was biased low by sensor failure could cause the observed underreporting of BHFS measurements compared to the tracer data.

To illustrate this, and because Dr. Allen and colleagues (1) found my comparison in (3) of their downwind tracer and on-site data (2) to be complex, I have tried to simplify that analysis here. Figure 1 presents the downwind tracer and on-site data from the UT study (2). For this analysis, I have removed only the two sites at which 98% or more of the reported on-site totals were comprised of estimated emissions, as opposed to actual BHFS measurements, since such a large fraction of estimated emissions would prevent a reasonable evaluation of the BHFS performance.

As seen in Figure 1, the downwind tracer data do in fact indicate that there are real regional differences in  $CH_4$  emissions from natural gas production, as (1) have asserted and as I have acknowledged in (3).

However, Figure 1 also shows clearly that the lower emissions in the Rocky Mountain region do not preclude the occurrence of BHFS sensor failure. When comparing the results on a site by site basis, the on-site totals (which as noted previously were a combination of BHFS measurements added to estimates of sources not measured) are substantially lower than the downwind tracer results for the Rocky Mountain and Mid-Continent sites where  $CH_4$  content was less than 82%, and substantially higher for sites in Appalachia where  $CH_4$  content was greater than 97% (sensor transition failure is much more likely at  $CH_4$  concentrations less than 97% (3)). Only one out of 13 sites with  $CH_4$  content < 82% (RM-5) had reported on-site emissions greater than the emissions measured by tracer, while all four sites with  $CH_4$  content > 97% had on-site emissions greater than those measured by tracer. The ratio of total on-site emissions to downwind tracer emissions for each region was as follows: Mid-Continent: 0.586; Rocky Mountain: 0.461; and Appalachia: 1.44.

Since the reported on-site emissions were greater than those measured by downwind tracer at all sites with well gas content of  $CH_4 > 97\%$  (the Appalachia region) where the BHFS likely functioned properly, I conclude that the estimation methods used by the UT study (2) actually overestimate emission rates as compared to actual whole-site emissions measured by downwind tracer analysis. Consequently, although this simplified comparison indicates that the on-site data are a factor of two too low at the Mid-Continent and Rocky Mountain sites, the actual effect of BHFS sensor failure is probably larger because the overestimates of emissions from the sources that were not measured somewhat obscures the underreporting by the BHFS, and I've discussed this in detail in (3). Therefore, although this direct comparison of the downwind tracer measurements to the on-site data for each site independently verifies the BHFS sensor failure, it does not reflect the full magnitude of the problem.

Given that the BHFS sensor failure can cause underreporting of natural gas emission rates which could create critical safety, health, and environmental problems, it is disappointing that (1) are willing to ignore the clear evidence – provided by their own downwind tracer measurements – of the effects of sensor failure in the UT BHFS (2) data set. The lead author of (1) and (2) served as the chair of the EPA Science Advisory Board during the period of research conducted by (2), and as such has a special obligation to disclose this issue since the BHFS is an EPA approved instrument. The BHFS is currently the standard instrument in the natural gas industry worldwide for measuring leak rates, and although upgrading firmware may reduce sensor failure, it does not eliminate it, and it is likely that most BHFS's in use have older firmware more susceptible to sensor failure. The presence of such a problem that can result in large leaks being reported as an order of magnitude or more lower than they actually are presents a frightening safety issue. It may have also caused many CH<sub>4</sub> emission inventories to be biased low, including those compiled by the USEPA Subpart W Greenhouse Gas Reporting program (9), the American Carbon Registry (10), and the United Nations Clean Development Mechanism (11).

For the last 12 years I have served as a professional firefighter, and in that role I have seen the tragic consequences that can occur when safety issues are ignored. Unfortunately, the misguided defense by such prominent researchers (1) of the UT BHFS data set (2) creates a distraction from the critical safety, health, and environmental problems that the BHFS sensor failure presents to the oil and NG industry. I call upon the authors and sponsors of the UT study (2) to meet their obligations to the safety of industry personnel and to the health of communities near oil and NG facilities by retracting the UT BHFS data set (2) so that this critically important problem can be recognized and addressed immediately.

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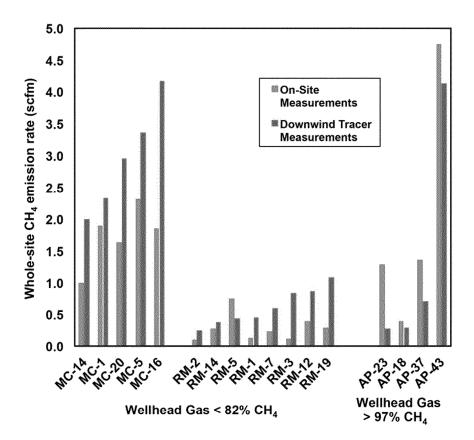
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#### **Figure Captions**

Figure 1. Comparison of downwind tracer measurements to reported on-site emission rates (compiled from BHFS measurements and estimates of sources not measured) in the UT study (2). Sites with lower CH4 wellhead gas content, where the BHFS is likely to experience sensor failure, have dramatically lower on-site emission rates compared to emission rates at the same sites measured by downwind tracer techniques. This comparison provides independent corroboration of the BHFS sensor failure, even in the Rocky Mountain region where tracer measurements indicate lower regional emission rates. BHFS = Bacharach Hi-Flow Sampler; MC = Mid-continent; RM = Rocky Mountain; AP = Appalachia.

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